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Transient multiphase flow simulation for unloading of frac hit gas wells

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TRANSIENT MULTIPHASE FLOW SIMULATION FOR UNLOADING OF FRAC HIT GAS WELLS

by

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ABSTRACT

This work seeks to develop a fully step-by-step transient multiphase flow simulation valid for unloading gas wells using nitrogen. It studies the behavior of nitrogen for unloading horizontal gas wells with gas injection in the annulus. The work investigates unloading non-Newtonian fluids such as those which invade offset wells when a frac hit occurs during hydraulic fracturing operations in unconventional wells. The effect of varying tubing depth and injection pressure are included in the study.

Results show that as the plastic viscosity increases, the nitrogen volume and time to unload will be increased. As tubing depth increases, the nitrogen volume and time to unload the liquid will be increased. However, deepening the tubing has the impact of sweeping more fluids from the lateral section and reducing the hold-up in the horizontal section.

As nitrogen injection pressure increases, the nitrogen volume and the time to unload the fluids decrease. Increasing the injection rate of nitrogen will increase the nitrogen volume required to unload but decrease the time to unloading.

Several case studies are simulated using methane as an alternative for nitrogen. The results show that unloading with methane requires a higher volume than nitrogen. Changing the casing size impacts the unloading process as well.

This work serves as a practical guideline for unloading frac hits in unconventional shale play gas wells.

ACKNOWLEDGMENTS

I would like to offer my humble gratitude to God. All of this could only be possible due to His generosity and mercy. His blessings guided me until reaching this point.

I would like to thank Dr. Shari Dunn-Norman for being my advisor all these years. She gave me the opportunity to get a scholarship through Missouri S&T. Without her financial support, I would never have achieved this goal. In addition, I extend my genuine gratitude to Dr. Mingzhen Wei, Dr. Ralph E. Flori, Dr. Abdulmohsin Imqam and Dr. Chatetha Chumkratoke for being part of my dissertation committee.

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I dedicate this work in memorial of my beloved granny Abi Ana. Abi, we did it!

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NOMENCLATURE

Symbol	Description
$Y\alpha$	Hold-Up for Alpha Phase
$Y\beta$	Hold-Up for Beta Phase
$V\alpha$	Volume of Alpha Phase
V	Total Volume
Us	Slip Velocity
$U\alpha$	Alpha Phase Average Velocity
$U\beta$	Beta Phase Average Velocity
$Us\alpha$	Alpha Phase Superficial Velocity
$q\alpha$	Alpha Phase Flow Rate
A	Cross-Sectional Area
g	Gravitational constant = 32.17 ft/s^2
gc	32.17 lbm-ft/lbf-s^2
d	droplet diameter
ρL	liquid density
ρG	gas density
CD	drag coefficient
Ad	droplet projected cross-sectional area
VG	gas velocity
Vd	droplet velocity

1. INTRODUCTION

1.1. BACKGROUND

The oil and gas industry has been developing shale plays with horizontal wells and multistage fracturing since the early 2000's. Initially, wells were drilled with significant separation, up to a half mile between laterals. These original wells are now referred to as 'parent' wells.

Low cumulative oil and gas recovery from parent wells quickly led industry to drill infill wells between the existing parent wells, referred to as 'child' wells. The laterals of these wells are commonly several hundreds of feet from the parent well. Since 2012, industry has been drilling more child wells than parent wells.

An unexpected and adverse result of infill drilling shale play wells has been the unintended intercommunication of the child well's fracturing stimulation treatment with the parent wellbore. Child well fracturing has frequently led to communication with an offsetting parent well, a phenomenon referred to as a 'frac hit'. Frac hits communicate both pressure and fluid to the affected well.

Industry has adopted the practice of placing plugs in offset, parent wells, to provide protection in parent wells surrounding the well that is being stimulated. (Esquivel & Blasingame, 2017) highlight two common practices to protect or prevent well-to-well fracture interference. Another practice is to load the parent well with fluid to create a hydrostatic pressure that helps to keep well integrity when frac hit reaches the parent well. (Whitfield, Watkins, & Dickinson, 2018) conducted research in the Eagle Ford and Permian Basins by preloading the parent wells before performing hydraulic fracture jobs in the infill/child wells. (Gala, Manchanda, & Sharma, 2018) proposed fluid injection in depleted parent wells to minimize the damage triggered by frac hits.

It has also been shown that frac hits can be strong enough to jeopardize the integrity of production tubing, casing and even wellheads (Jacobs, Oil and Gas Producers Find Frac Hits in Shale Wells a Major Challenge, 2017). (Pathak, et al., 2018) evaluated some of the key parameters to define frac hit risk at the Aishwarya Barmer-Hill Field. The researchers characterized the risk into four categories. With the highest severity damage risk, the authors explained that the cement and casing are damaged because the frac hits attacked well integrity.

A number of authors suggest methods of preventing such interference (King, Rainbolt, & Swanson, 2017), (Sani, Podhoretz, & Chambers, 2015), (Esquivel & Blasingame, 2017), yet there are no universally demonstrated means of preventing frac hits.

Despite the precautions taken to protect offset wells today, the ever-increasing density of lateral wells has led to a prevalent occurrence of frac hits in unprotected offset producing wells, i.e. producing wells not immediately adjacent to the stimulated well. When this occurs, the frac hit floods the affected producer with liquid, and often some volume of proppant. The volume of liquid that enters the affected wellbore rises in a vertical column, which generates hydrostatic pressure and kills production from the well. Once a well is ‘killed’ by a frac hit, the fluid must be removed from the wellbore so that production can be re-established.

When the killed well is a gas well, liquids are most commonly removed by injecting natural gas from an offset well into the killed well, to achieve a gas velocity sufficient to lift the liquids and re-establish natural flow. However, in cases where there is only one well on a pad, or where there is insufficient gas production, it may be necessary to use nitrogen for unloading the killed well. Nitrogen services are available in different volumes and pump pressures, so engineers require an understanding of the volumes to request for wellbore unloading. While much work has been done in the area of quantifying well unloading with coiled tubing services, little work has been focused on unloading a horizontal gas well after a frac hit.

This work seeks to develop a transient multiphase flow simulation using OLGA software, valid for unloading horizontal gas wells using nitrogen. The simulation provides a basis to examine the impact of lateral well geometry (toe up, toe down), injection rate and injection pressure, injection depth (varying end of tubing depth), and tubing-casing volumes to displace. Unloading with methane is also included to simulate unloading with natural gas.

Results of this work provide an estimate of nitrogen volumes required for unloading frac hit wells. The methane injection results provide an understanding of unloading characteristics of gas lift with no valves in place.

1.2. RESEARCH OBJECTIVES

The objectives of this research are:

1. To develop a transient multiphase flow simulation for unloading frac hits of gas wells using nitrogen injection.
2. To study the behavior of nitrogen for unloading gas wells when well survey differs from the vertical given the same injection depth.

3. To investigate the effect of non-Newtonian frac hit fluids in the unloading gas well technique.
4. To investigate the effect of progressively increasing injection depth along the lateral of the horizontal well.
5. To analyze the effectiveness of the unloading process when flow rate, and injection pressure of nitrogen differ from the base case.
6. To study the behavior of methane for unloading.
7. To study the behavior of the unloading process using nitrogen when casing and tubing size change.
8. To express the results of the simulation work in a practical figure so that nitrogen volumes for various cases studied are summarized in a useful way.

1.3. THE SCOPE AND ASSUMPTIONS OF THE RESEARCH

The scope and assumptions of this research consist of:

1. The simulation covers from the wellbore up to the wellhead.
2. The temperature effects in the system are being considered.
3. The fluid flow in the system is three phase flow including, gas, oil, and brine. No proppant flow is included.
4. The composition of the nitrogen in the system is homogenous and the nitrogen is injected as a gas with no cooling effect.
5. The loading liquid in the system represents the consequence of the impact of frac hits.

6. The composition of the gas and oil is not being reported but still being considered in the overall results.
7. Nitrogen and natural gas mixture are not considered.
8. Reservoir simulation is not considered. A normalized backpressure IPR is used for inflow.
9. The completion does not consider packers.

1.4. RESEARCH METHODOLOGY

The methodology of this study consists of four sections including the literature review, transient multiphase model simulation results and analysis, sensitivity analysis and research conclusions and discussions.

1.4.1. Literature Review. This section compiles the fundamental knowledge and research related to this study. Starting from defining frac hits, going through factors that induce frac hits, and mitigating the impact of frac hits. From a production perspective, the literature review summarizes some fundamental gas well unloading references and modeling work related to gas well unloading. Transient Multiphase Model Simulation. This section describes the transient multiphase flow model simulation of this work.

The section also includes the principle of transient multiphase simulation, the detail of the model in the simulator, the geometry and discretization, and the computer simulation analysis and results.

1.4.2. Sensitivity Analysis. This section describes the behavior of the nitrogen being injected in the wellbore to unload the gas well.

The impact of changing variables such as the well inclination, tubing end of depth (EOT), tubing and casing size, loading liquid density, nitrogen injection rate, and nitrogen injection pressure are included as a sensitivity analysis.

1.4.3. Research Conclusions And Discussions. This section explains the conclusion and discussion of this research. Figure 1.1 shows the flowchart of the research methodology used in this study.

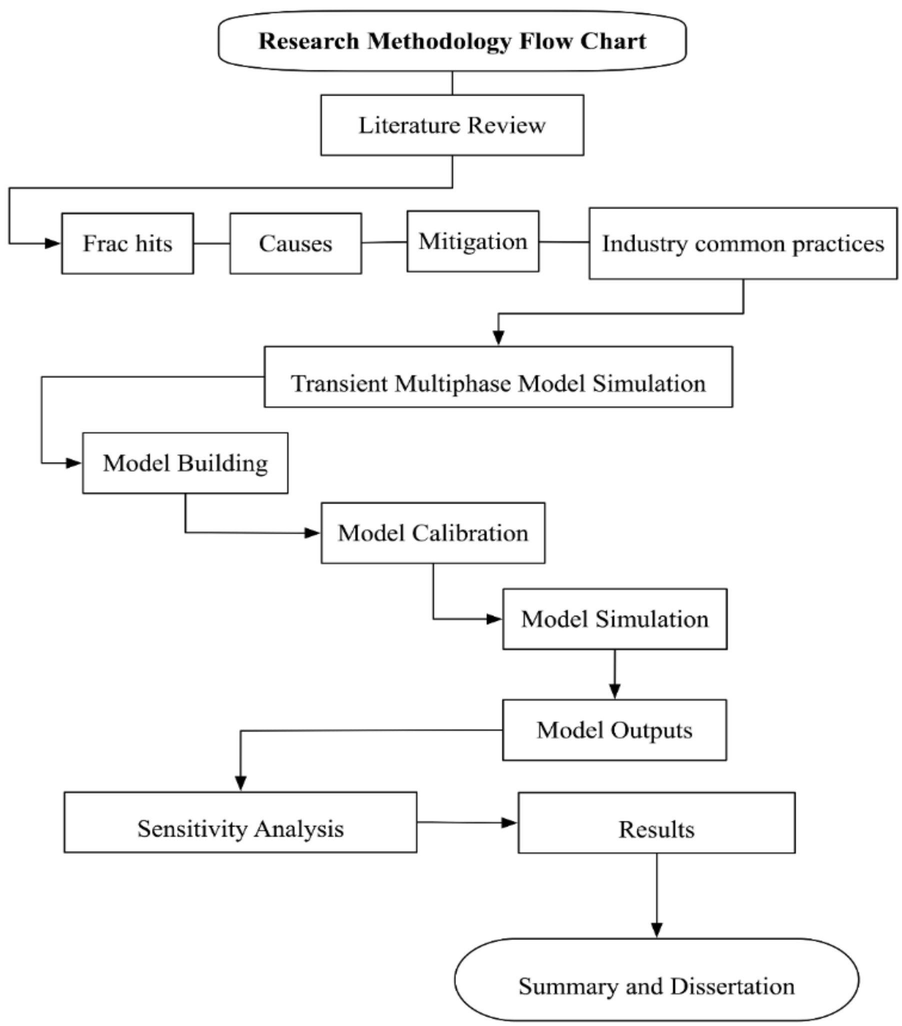


Figure 1.1. Flowchart Of This Research Study

2. THEORETICAL BACKGROUND AND LITERATURE REVIEW

2.1. MULTIPHASE FLOW

Multiphase flow is a significant topic and a complete review is beyond the scope of this dissertation. Nevertheless, it is necessary to understand some fundamentals of multiphase flow as background to gas well unloading and the simulation used in this work.

Figure 2.1 shows a segment of a pipe where two phases are flowing.

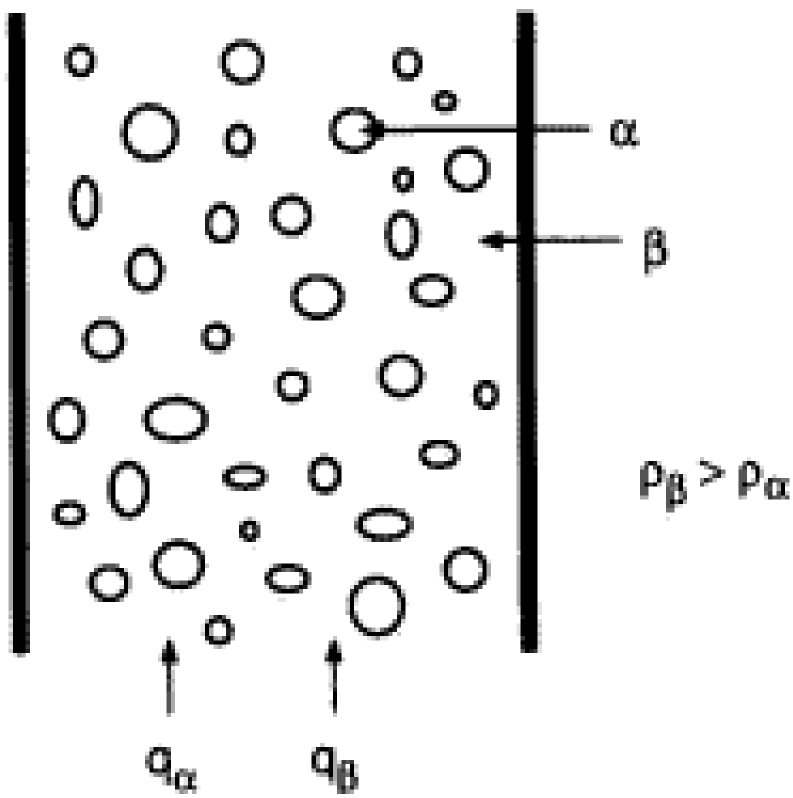


Figure 2.1. Multiphase Flow In A Vertical Pipe
(Economides, 2004)

Alpha is the lighter phase, and beta is the denser phase. In oil and gas wells, the lighter phase is gas, and the denser phase is liquid, such as oil, water or a mixture of both.

There are three important terms in multiphase flow used to describe flow characteristics. These terms are holdup, slip velocity and superficial velocity, described in the following equations.

$$y_\alpha = \frac{V_\alpha}{V} = 1 - y_\beta \tag{1}$$

$$u_s = \overline{u_\alpha} - \overline{u_\beta} \tag{2}$$

$$u_{s\alpha} = \frac{q_\alpha}{A} \tag{3}$$

Equation (1) is the holdup, which physically quantifies the tendency for the gas phase to move faster past the liquid phase and for the liquid to be ‘held up’ in the flow along the pipe relative to the gas. It is the ratio of the volume of either phase in a segment of the pipe relative to the total volume.

Equation (2) is slip velocity which is the difference between the average velocity of each phase. Equation (3) is superficial velocity which is a representation of the velocity of each phase as if it was flowing by itself in the pipe.

Therefore, it is the ratio of the flow rate of that phase, divided by the total cross-sectional area.

2.2. SUPERFICIAL VELOCITY AFFECTS FLOW REGIME

Superficial velocity can be used to characterize vertical well flow regimes. Figure 2.2 shows flow regimes in a vertical well when the superficial velocity of the liquid and gas change.

For example, if the superficial gas velocity is low, for example 0.1, and the superficial liquid velocity is also low, the flow regime is bubble flow or gas dispersed.

If the superficial gas velocity increases to 100 while keeping a superficial liquid velocity of 0.1, the flow regime is an annular flow fully of gas.

Moving to the other extreme, if the superficial gas velocity is 0.1 while the superficial liquid velocity is high, the flow regime is represented by a flow of pure liquid with very few gas bubbles.

The flow regimes shown in Figure 2.2 describe the gas-liquid flow characteristics when different combinations of each fluid are flowing. Each flow regime has an associated pressure loss behavior.

Hence, understanding flow regimes and holdup are fundamental concepts in wellbore flow.

2.3. PROGRESSION OF LIQUID LOADING IN VERTICAL WELLS

In gas wells, liquids are being removed from the well when the flow regime is annular mist flow (high superficial gas velocity and low liquid superficial velocity). As a gas well's reservoir pressure declines, the gas production and gas flowing velocity decreases. Figure 2.3 depicts the change in flow regime when this occurs. As gas flow rate decreases, slugs of liquid form in the wellbore and are produced at the surface.

This is referred to as slug flow. As gas production continues to decrease, a liquid column builds in the wellbore until eventually only a few bubbles of gas are moving through the liquid.

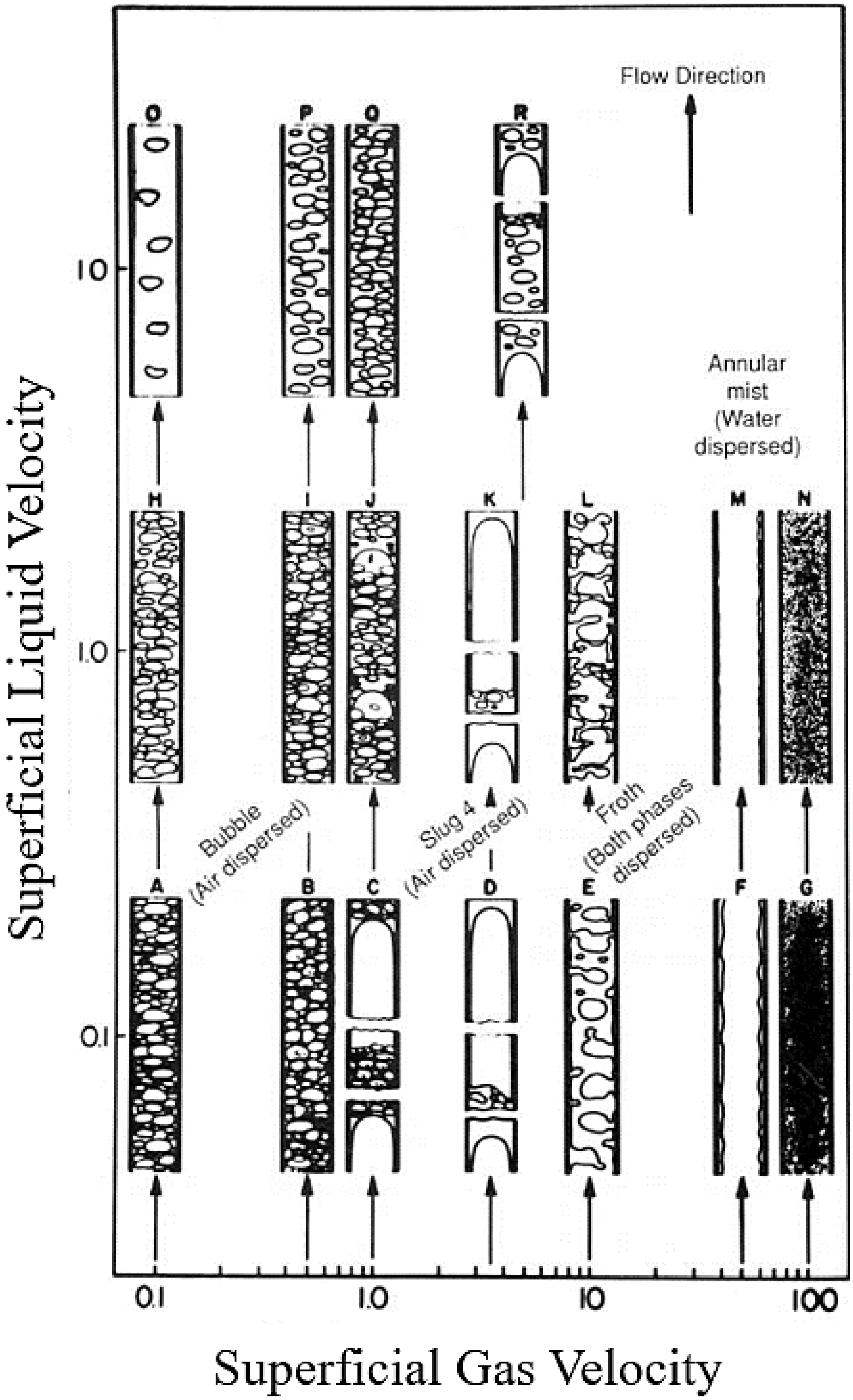


Figure 2.2. Flow Regimes In Vertical Wells
(Economides, 2004)

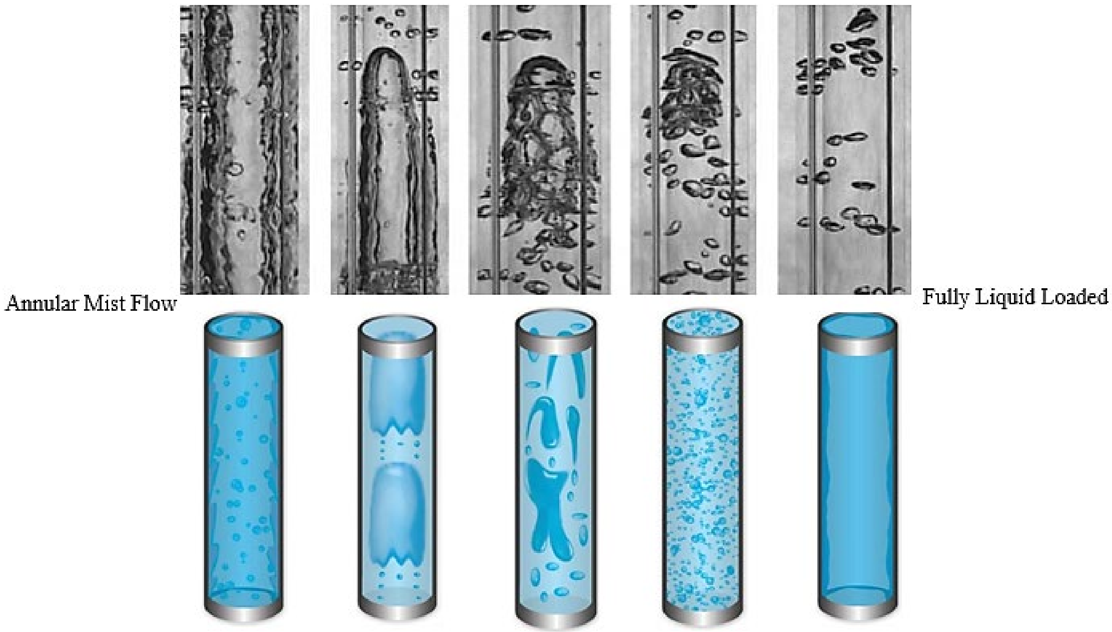


Figure 2.3. Progression Of Liquid Loading In Vertical Wells
(http://www.drbratland.com/PipeFlow2/chapter1.html, 2018)

Figure 2.4 provides a slightly different view of the same vertical well liquid loading phenomena.

In this figure, the picture depicts tubing landed above a larger diameter casing. The well's production decline is plotted against a progression of loading phenomena.

At first, the well appears to be producing unloaded, but liquid loading (slug flow) has started in the larger casing annulus and then progresses up the tubing.

At some point slug flow reaches the top of the tubing and is seen as erratic production. As pressure and flow decreases, the flow regime changes toward bubble flow.

Production in the well is greatly reduced, and the well may ultimately cease to flow at all.

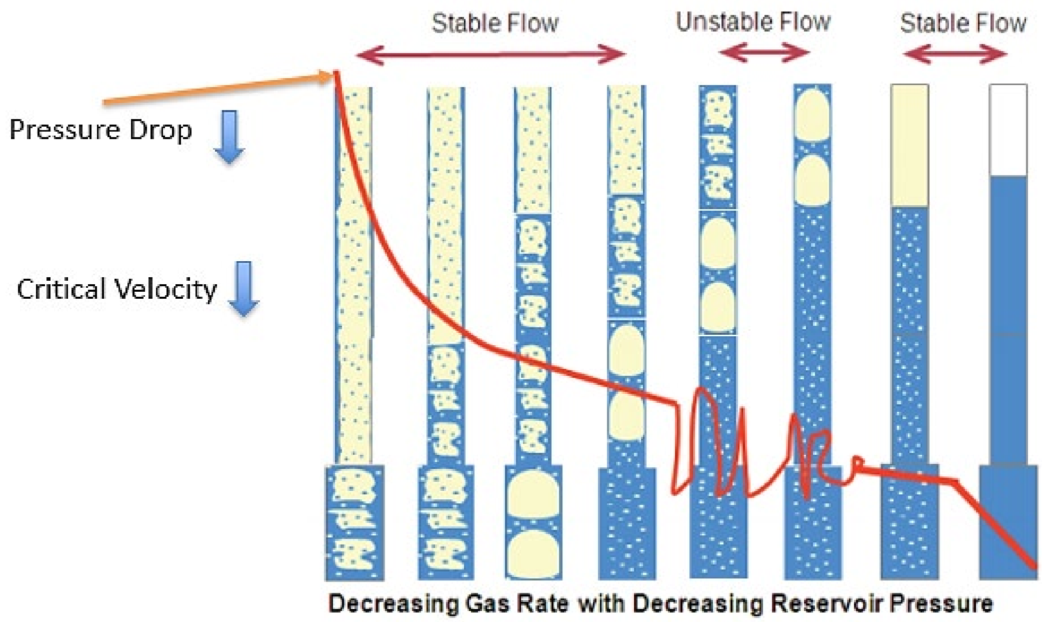


Figure 2.4. Progression Of Liquid Loading In A Producing Vertical Well (Hearn, 2010)

It is important to note that a frac hit well does not experience this transitional flow regime phenomena as it is killed by a frac hit. The loading occurs instantaneously, as a result of rapid fluid invasion into the wellbore.

2.4. TWO-PHASE FLOW REGIMES IN HORIZONTAL WELLS

Multiphase flow regimes in horizontal wells differ from those in vertical wells, primarily due to gravity. Figure 2.5 depicts a flow regime map for horizontal multiphase flow. As shown previously, the flow regime varies as a combination of superficial gas and liquid velocities. Here the flow regimes include stratified-smooth flow and stratified-wavy flow, which mainly occur as a consequence of gravity.

Other horizontal flow regimes include dispersed-bubble, elongated bubble, slug, churn, and annular flow. Most horizontal wells produce in stratified flow. It is important to note that in a frac hit, liquid enters in the lateral, or horizontal section of the affected well. However, a tubing string will be in place in the vertical section of the well. Hence, both vertical and horizontal flow regimes are of importance in unloading a frac hit well.

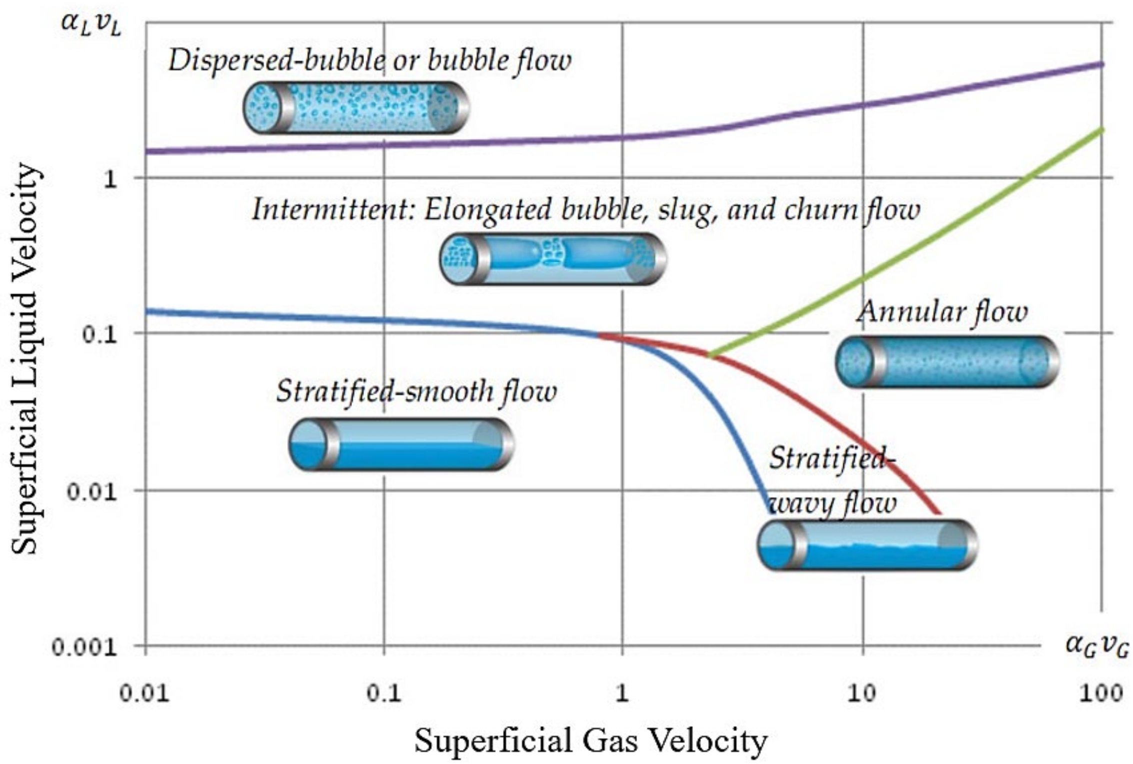


Figure 2.5. Flow Regimes In Horizontal Wells
(http://www.drbratland.com/PipeFlow2/chapter1.html, 2019)

2.5. TURNER CRITICAL VELOCITY DROPLET MODEL – NOT FILM MODEL

Another means of identifying liquid loading in a vertical well or tubing is critical gas flow velocity. In 1969, Turner developed a simple equation for predicting when loading will occur in a vertical, producing gas well.

He assumed that there is a critical velocity which occurs when the gas velocity creates a drag force across a liquid drop that is exactly equal to the gravitational force on the liquid drop. Equations for these forces, and Turner's critical velocity equation are included here as this is an important and widely used characterization of liquid loading.

Figure 2.6 illustrates the body diagram for a liquid particle in which the drag and gravity forces are being applied.

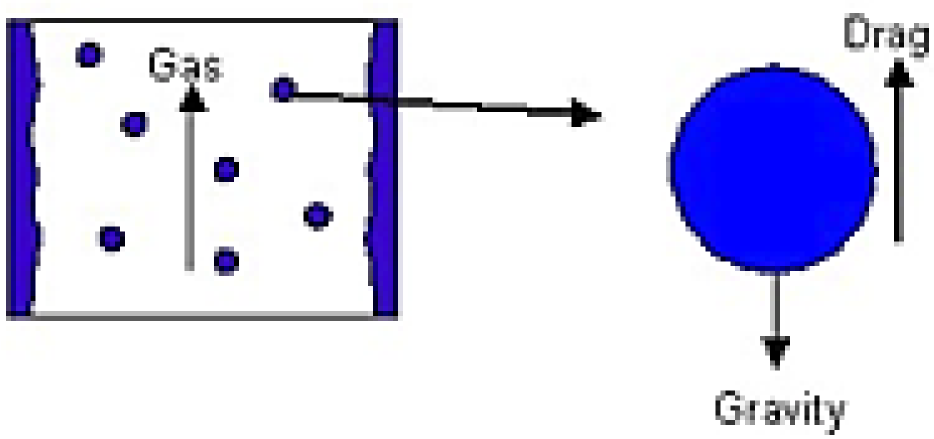


Figure 2.6. Liquid Transport In A Vertical Well

$$F_{Gravity} = \frac{g}{g_c}(\rho_L - \rho_G)\frac{\pi d^3}{6} \tag{4}$$

$$F_{Drag,UP} = \frac{1}{2g_c}\rho_G C_D A_d (V_G - V_d)^2 \tag{5}$$

$$Turner_{Equation} \rightarrow F_{Gravity} = F_{Drag,UP} \tag{6}$$

$$Turner_{Equation} \rightarrow v_{G,T} = 6.558\left[\frac{\sigma(\rho_L - \rho_G)}{\rho_G^2}\right]^{0.25} \tag{7}$$

Where, **g** is Gravitational constant = 32.17 ft/s^2, **gc** is 32.17 lbm-ft/lbf-s^2, **d** is droplet diameter, **ρL** is liquid density, **ρG** is gas density, **CD** is drag coefficient, **Ad** is droplet projected cross-sectional area, **VG** is gas velocity, and **Vd** is droplet velocity.

2.6. FRAC HITS BETWEEN LATERALS

To better understand how frac hits affect producing gas wells, it is required to define a frac hit. Figure 2.7 represents the sequence that illustrates what a frac hit is and how it is produced. There are six main stages where a frac hit is created.

At the beginning a horizontal parent well is drilled. The well is stimulated by hydraulic fracture job to produce from the gas shale reservoir. After certain time, another infill well is drilled, this well is called child well. Like the parent well, the child well must be stimulated to produce. In the process, during the 3rd stage of hydraulic job, a sudden connection between the parent well and the child well is created. Throughout this connection, the frac fluid from the child well invade the producing parent well. The frac fluid fulfills the parent well. The parent well is not able to produce gas because of the frac fluid invasion. This is called a frac hit. Industry normally uses retrievable bridge plugs placed in offsetting wells (adjacent wells), to prevent frac fluids from reaching the surface in offsetting well, when they are performing hydraulic fracture treatments.

When a frac hit kills a well, the fluid must be removed to restore production. Typically, industry uses natural gas or nitrogen, but foam can also be used. There is an evolving body of literature regarding frac hits. Most of these references addresses methods of predicting frac hits or avoiding frac hits. Although this is not the primary focus of this study one reference to frac hits is included at the end of the literature review.

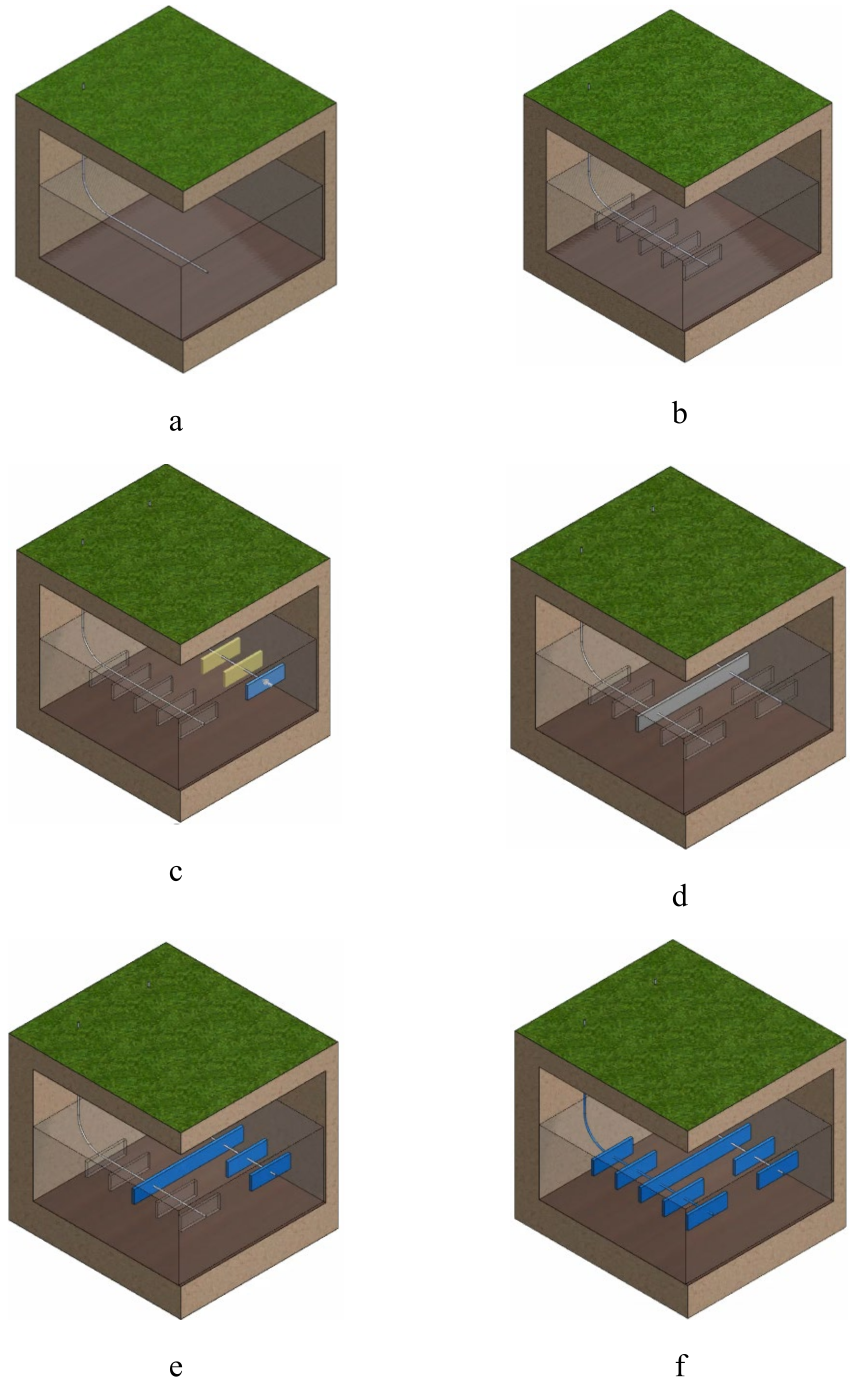


Figure 2.7. Frac Hits Creation. A) Horizontal Parent Well. B) Hydraulic Fracture Job In Parent Well. C) Hydraulic Fracture Job In Adjacent Well. D) A Sudden Connection Between Parent Well And Adjacent Well. E) Frac Fluid From Adjacent Well Invades Parent Well Using The Connection Already Created For The Hydraulic Frac Job At The Adjacent Well. F) Parent Well Is Loaded By Frac Fluid From Adjacent Well

2.7. LITERATURE REVIEW

There is a wide body of literature which discusses various aspects of gas well unloading. (Watson & Graham, 2003) discussed a rule of thumb to calculate the unloading process for wells. They proposed equations that ae not disclosed, however those correlations consider temperature and pressure of gas volume, equations for volume of gas to run the unloading and basic calculation of friction from flow in compressible gasified systems. (Salim & Li, 2009) conducted simulations to unload gas wells using coiled tubing (CT).

Their paper describes transient software which was developed to determine the nitrogen volume and cleaning time required to unload gas wells.

(Zhou, Smalley, Opel, & Ctes, 2011) determined the optimum nitrogen injection rate to unload gas wells using coiled tubing based on the minimum BHP. Their results showed that by increasing nitrogen rate, the hydrostatic pressure in the annulus and BHP decrease, however, after certain limit rate value, the friction pressure loss in the annulus increases leading the BHP to increase as well.

(Gu, 1995) discussed several transient aspects of unloading gas and oil wells using coiled tubing. Their simulations included multiphase mass transport equations and gas rise in the wellbore liquid below the coiled tubing.

Their results showed that CT size and depth affect the unloading process. (Nascimento, Becze, Virues, & Wang, 2015) simulated the optimization of start-up of horizontal wells using plunger lift as artificial lift method using OLGA.

(Pradhan & Xiong, 2017) coupled reservoir simulation with transient multiphase wellbore models to optimize production in horizontal wells.

This following, more detailed review focuses specifically on nitrogen unloading of wells and other, related modeling efforts in gas well unloading.

One paper related to frac hits is included as there is a growing body of knowledge on this subject.

2.7.1. Transient Aspects Of Unloading Oil And Gas Wells With Coiled Tubing. (Gu, 1995) presented a publication where conveyed nitrogen circulation is used to unload oil and gas wells with coiled tubing. It calculated the nitrogen volume and operation time for unloading a well.

The simulation included transient multiphase mass transport to measure the different type of fluids inside the well. (Gu, 1995) used vertical wells as case studies.

Figure 2.8 shows the flow rates out of the well during unloading for wellbore fluid with a specific gravity of 1.

Figure 2.9 shows that increasing the specific gravity, it would require a higher flow rate of nitrogen injection to unload a vertical well while keeping the same time to unload.

(Gu, 1995) suggested that more nitrogen and longer time would be required to unload a well where its fluid is being removed from the reservoir contact.

The density of the fluid inside the wellbore plays an important role in the unloading process.

2.7.2. Simulation Of Liquid Unloading From A Gas Well With Coiled Tubing. (Salim & Li, 2009) introduced a transient software simulator for liquid unloading using coiled tubing. Using experimental test results obtained by a scale flow loop shown in Figure 2.10, a critical gas velocity model was built.

Their model determines the volume of liquid that can be lifted for a different gas rate.

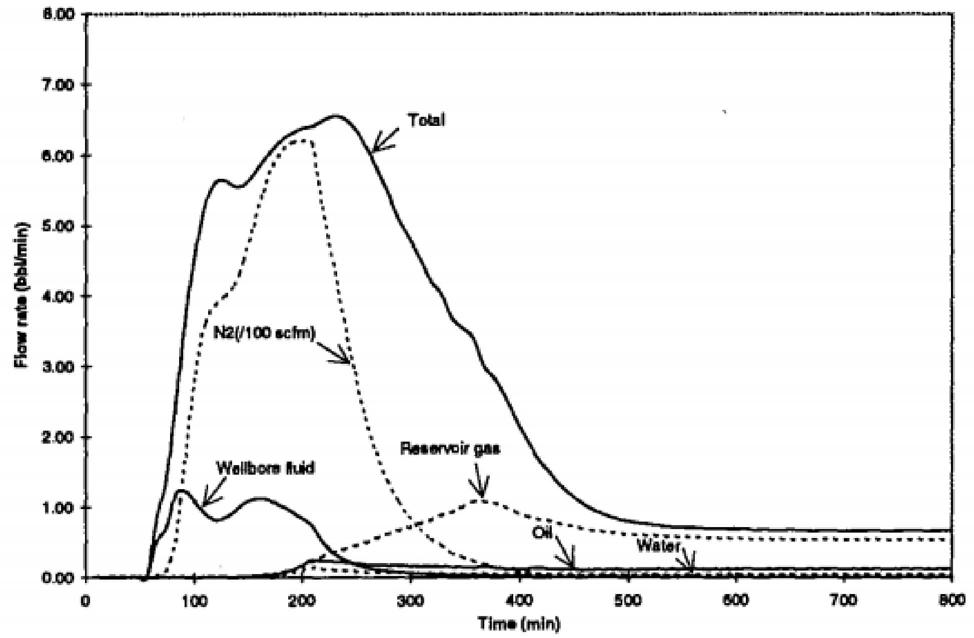


Figure 2.8. Flow Rates Out Of Well During Unloading For Wellbore Fluid With SG=1
(Gu, 1995)

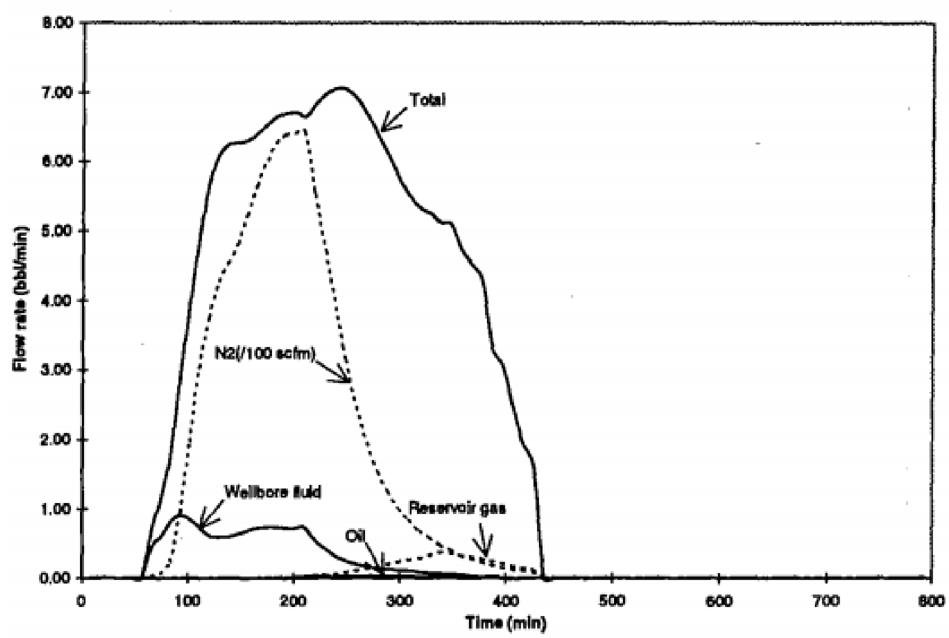


Figure 2.9. Flow Rates Out Of Well During Unloading For Wellbore Fluid With
SG=1.15
(Gu, 1995)

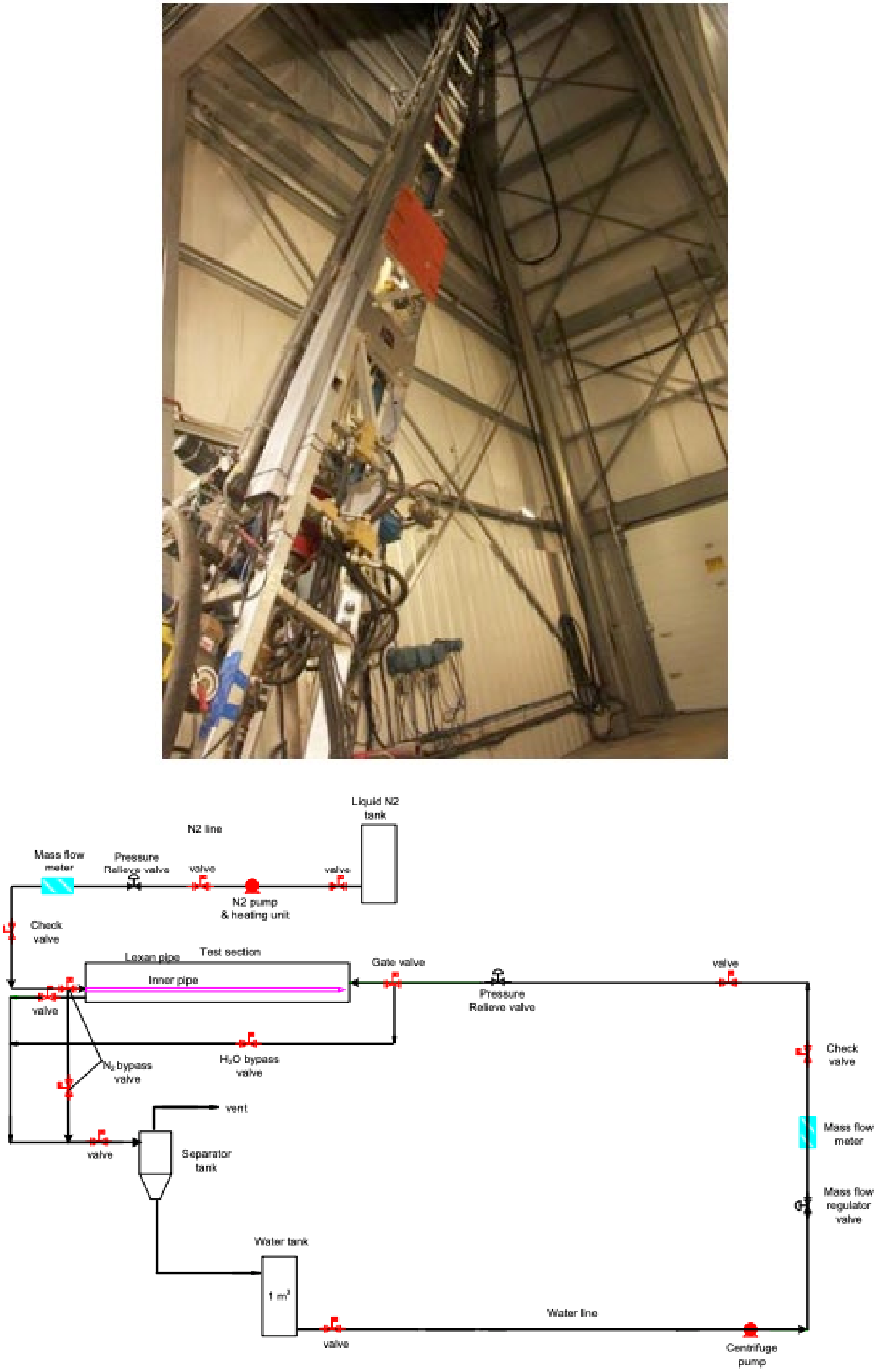


Figure 2.10. Scale Flow Loop System
(Salim & Li, 2009)

As a conclusion, the interaction between the reservoir and wellbore could affect the simulation process and therefore the transient behavior of the unloading process.

2.7.3. Optimum Nitrogen Rate For Unloading Gas Wells With Coiled Tubing. (Zhou, Smalley, Opel, & Ctes, 2011) conducted research to investigate the optimum nitrogen injection rate based on the criterion of minimum bottom hole pressure.

Simulation results showed that the injection rate increases when the hydrostatic pressure in the annulus and the bottom hole pressure decrease.

However, increasing the injection rate beyond a certain limit might increase the friction pressure loss in the annulus significantly, which implies that the BHP would increase as well, especially when gas wells annulus is small.

Smaller wellbores have annular friction loss as a limiting factor. Their research experiments were developed for vertical wells.

Figure 2.11 illustrates the relationship between the BHP and nitrogen injection rate for different depth of injection.

(Zhou, Smalley, Opel, & Ctes, 2011) noticed that if the nitrogen injection depth increases, the minimum bottom hole pressure can be described as a linear equation as shown in Figure 2.12.

As expected, if a higher liquid unloading rate is needed, the nitrogen injection rate would have to be increased.

Finally, the authors suggested that the liquid unloading in deviated wells and horizontal wells might be more difficult than vertical wells due to phase separation and different flow regimes.

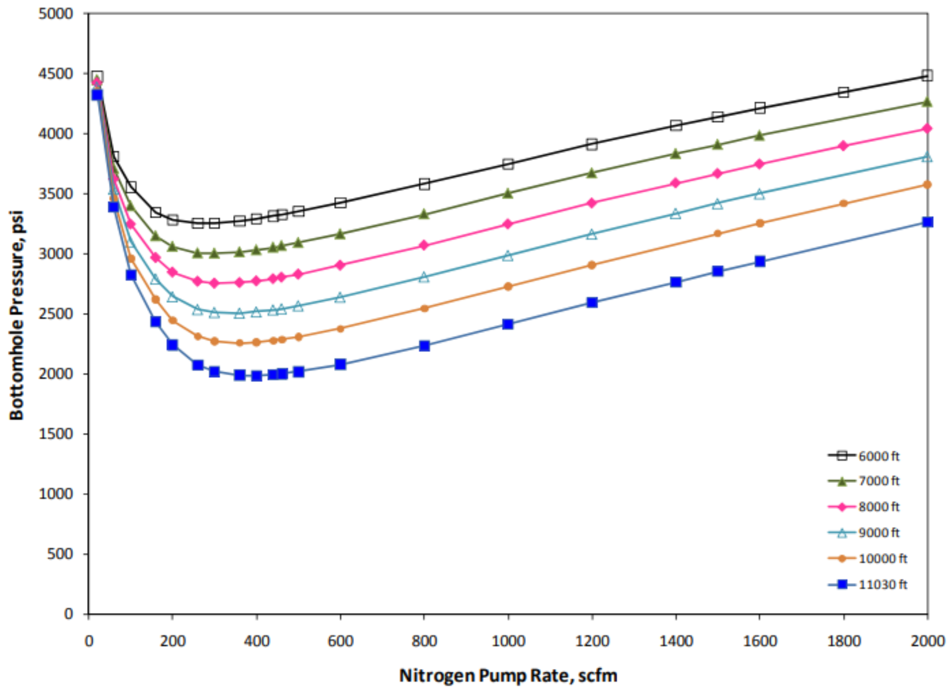


Figure 2.11. Nitrogen Injection Vs BHP
(Zhou, Smalley, Opel, & Ctes, 2011)

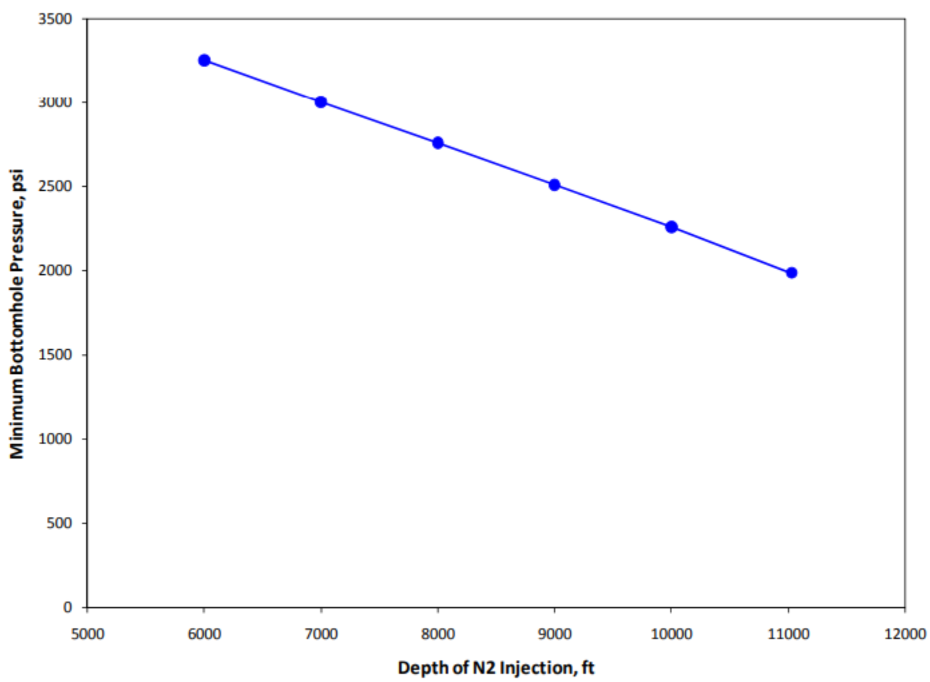


Figure 2.12. Minimum Bhp Vs Depth Of N2 Injection
(Zhou, Smalley, Opel, & Ctes, 2011)

2.7.4. Calculating A Rule Of Thumb For Unloading A Well. (Watson & Graham, 2003) proposed a rule of thumb to calculate the amount of initial gas volume required to unload a well.

Their experiments use the basic equations to calculate the volume of gas applying the Z factor. It is used basic correlations for temperature and pressure to gas volumes. Finally, a basic calculation of friction from flow in compressible gasified systems is used.

Using the "U" tube principle, the different densities and pressure relationship is taken in place. As a conclusion, the rule of thumb proposed by (Watson & Graham, 2003) is:

- @ 10,000 feet use 900 SCFM
- @ 15,000 feet use 700 SCFM
- @ 20,000 feet use 500 SCFM

2.7.5. Starting-Up Horizontal Wells And Evaluating Plunger Lift Using OLGA. (Nascimento, Becze, Virues, & Wang, 2015) mention that a proper clean up procedure at the early stages is needed to maximize the efficiency.

If the well faces a non-adequate cleanup course of action, the liquid in the wellbore might increase making the subsequent start-up attempts even more demanding.

The authors researched a simulation about gas well liquid loading due to production, gas well deliquification using plunger lift and optimization of the start-up of the well. Figure 2.13 illustrates the well trajectories for three wells observed in this study.

Figure 2.14 represents the simulation for gas flow rate while liquid loading, where the blue line is the total liquid content in the system, red line is the BHP, and the black line is the gas volume flow at standard conditions of the wellhead.

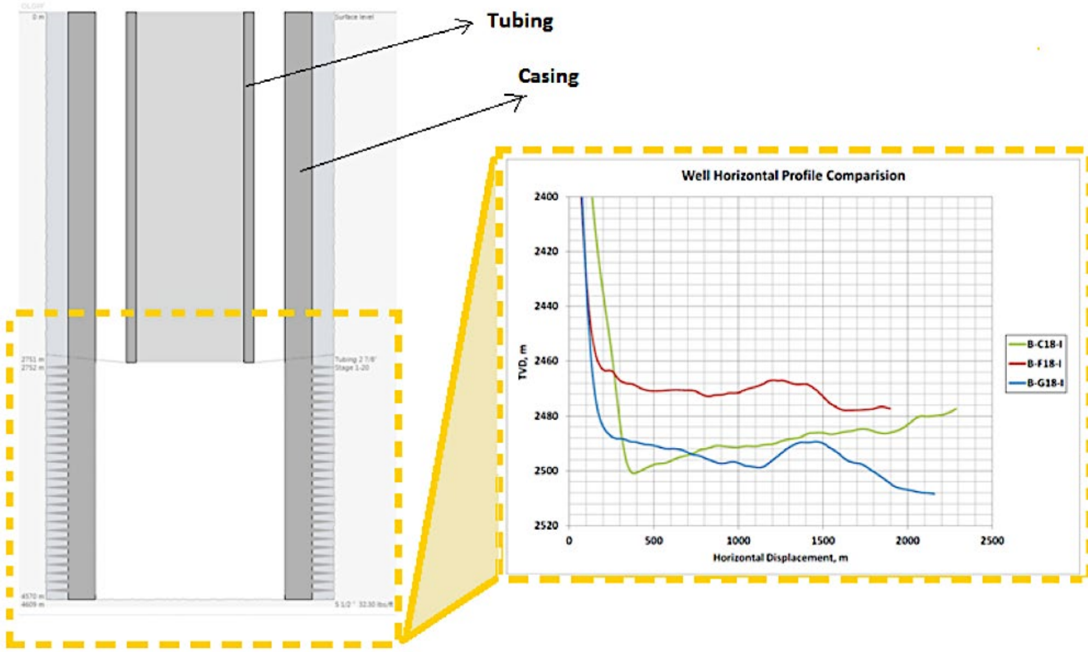


Figure 2.13. Well Trajectories
(Nascimento, Becze, Virues, & Wang, 2015)

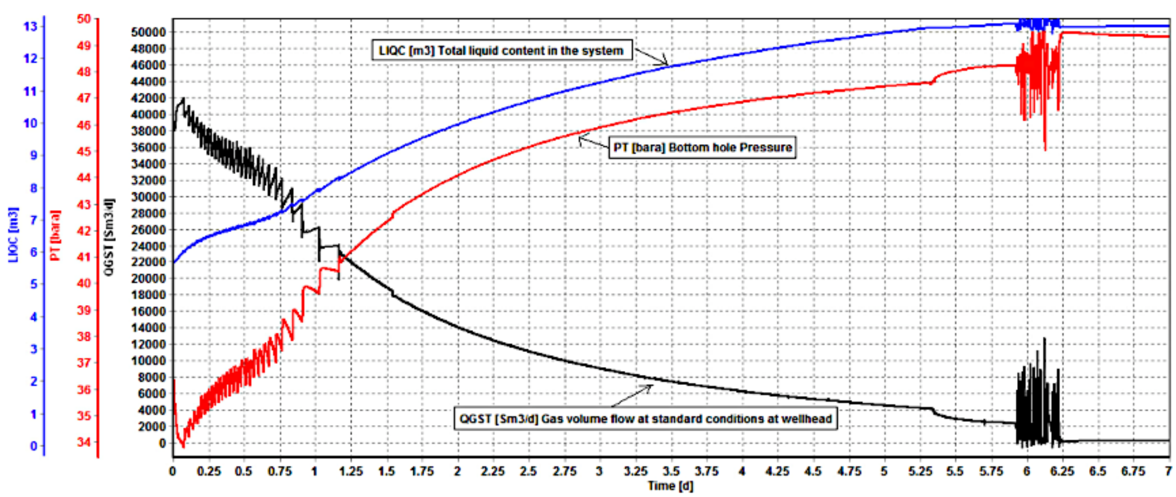


Figure 2.14. Liquid Hold-Up And Gas Flow Rate When Loading
(Nascimento, Becze, Virues, & Wang, 2015)

As shown in Figure 2.14, the red line represents the pressure at the bottom hole, the blue line stands for the total liquid content (hold-up), and the black line shows the decreasing of the gas flow rate due to the liquid loading.

Later, the authors simulate the liquid unloading using Plunger Lift as an Artificial Lift method described in Figure 2.15.

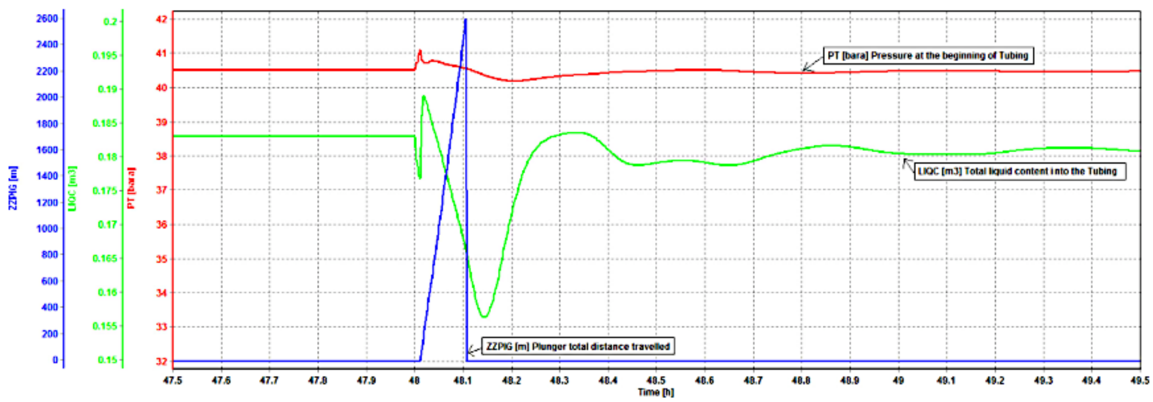


Figure 2.15. Unloading With Plunger Lift
(Nascimento, Becze, Virues, & Wang, 2015)

Figure 2.15 shows a blue line which represents the action of the plunger total-distance traveled. When the plunger is downhole and coming to the surface, it lifts up some of the liquid at the tubing. That is the reason why the green line, total liquid content in the tubing, starts to decrease at a slow rate. While changing the frequency of the plunger, the hold-up can be reduced faster.

Figure 2.16. shows that the cumulative gas production at wellhead increases significantly when the plunger frequencies increase as well. The purple line represents a plunger working each 30 min. The blue line represents a plunger acting every hour. The

red line shows the behavior of a plunger working every two hours while the green line shows a plunger lifting up the liquid every 24 hours.

There are many other considerations when decreasing the time of acting for the plunger. Certain impediments restrict the use of this artificial method as well.

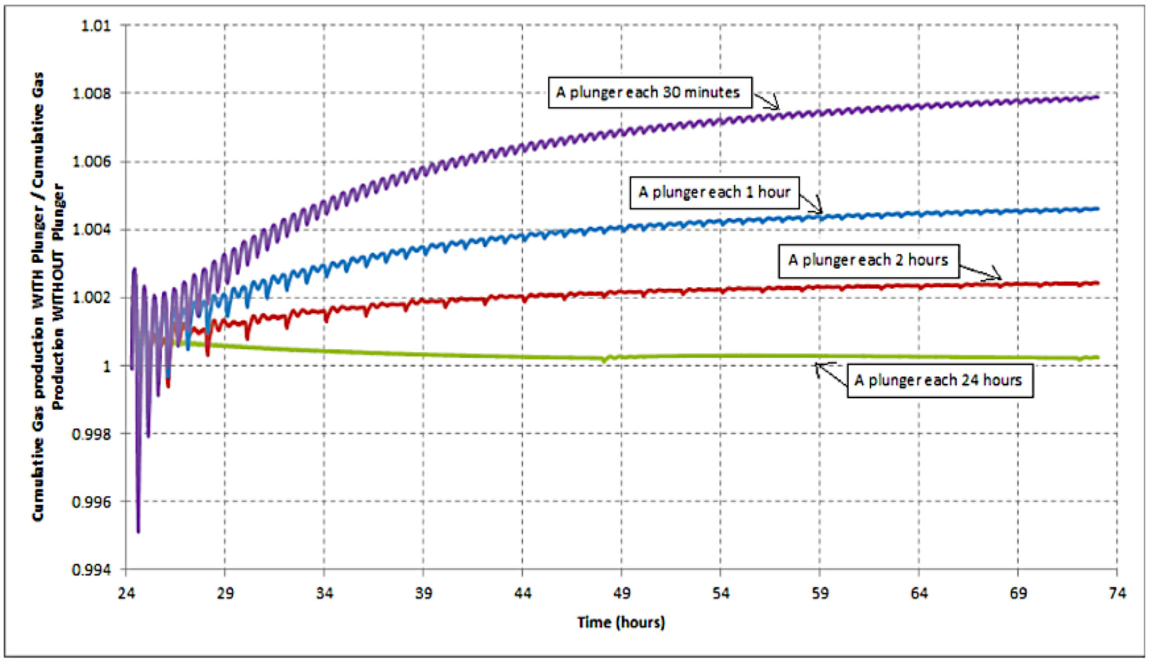


Figure 2.16. Plunger Frequencies In Unloading Gas Wells
(Nascimento, Becze, Virues, & Wang, 2015)

All the literature is referred to unloading producing wells, whereas my research more focuses on unloading a well killed by an instantaneous frac hit.

The difference is that in a producing well where liquid loading is expected, it is usually installed some permanent artificial lift system.

In a frac hit situation, we are looking for the volumes needed to unload the well one time without changing the completion.

2.7.6. Production Optimization Through Lateral Multi-Phase Flow Simulation. (Pradhan & Xiong, 2017) presented a multi-phase flow simulation for horizontal wells focusing on production optimization.

Their study contained two sections. The first section deals with reservoir simulation to match historical well production data. Once the first task is completed, the authors studied the impact of wellbore trajectory and lateral length on well performance.

Reservoir Simulation. The reservoir simulation was matched with data obtained from Lower Spraberry well from the Northern Midland Basin and Wolf-camp B well from the Southern Midland Basin. Both wells belong to the University Land. Using a single cluster dual porosity simulation model, the author calculated reservoir pressure, gas oil ratio (GOR) and water cut. This information is required to wellbore flow simulation. Figure 2.17 represents the reservoir model used for RTA simulation.

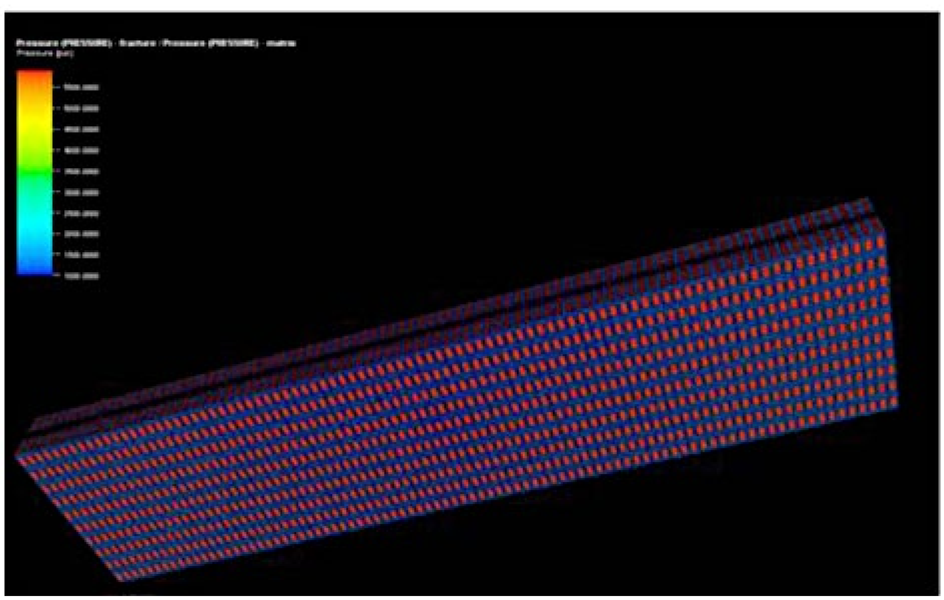
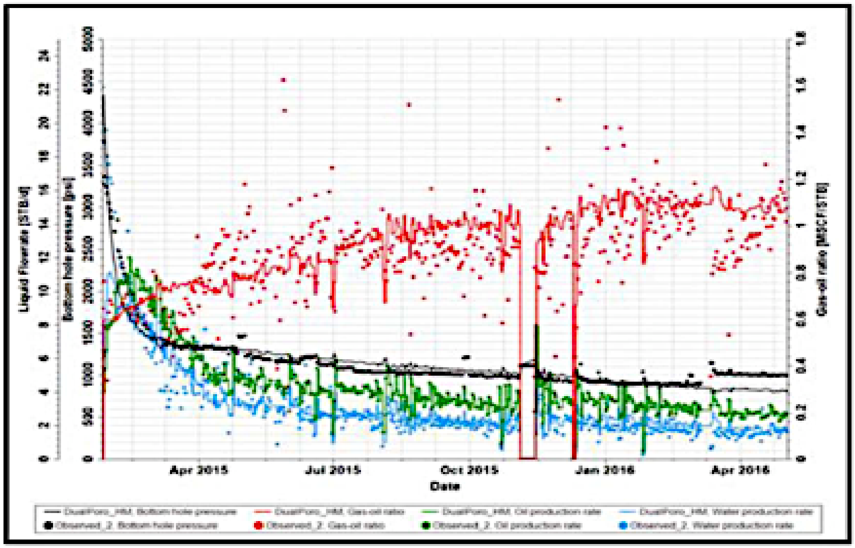


Figure 2.17. Reservoir Model
(Pradhan & Xiong, 2017)

Figure 2.18 shows the history matching for both wells, which means that the productivity index, reservoir pressure, water cut, and gas oil ratio are validated values.



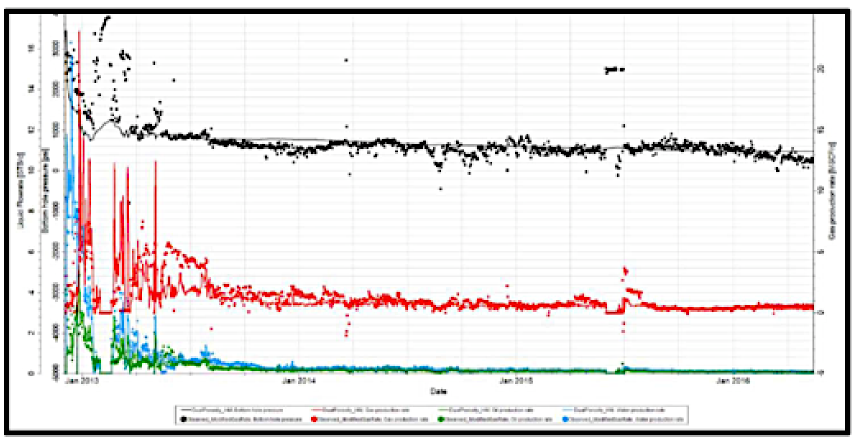


Figure 2.18. History Matching For Both Wells
(Pradhan & Xiong, 2017)

Once the RTA simulation is completed, the next step was to build a multi-phase flow simulation in OLGA to quantify the bottom hole pressure and liquid hold-up as the result of different well trajectories. Figure 2.19 shows those parameters when the well trajectory is the original survey. Figure 2.20 shows the behavior when the well trajectory is a truncated trajectory.

Figure 2.21 shows the behavior when the well trajectory is a toe-up trajectory.

Figure 2.22 shows those parameters when the well trajectory is a toe-down trajectory.

Figure 2.23 shows those parameters when the well trajectory is an undulated trajectory.

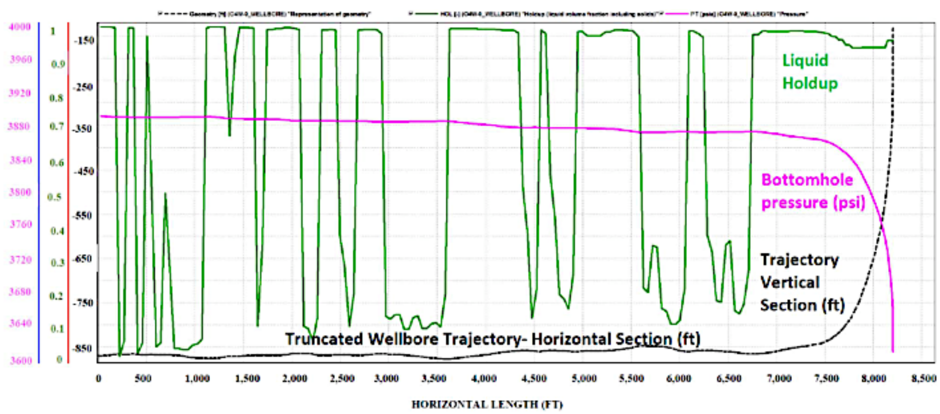


Figure 2.19. Original Trajectory
(Pradhan & Xiong, 2017)

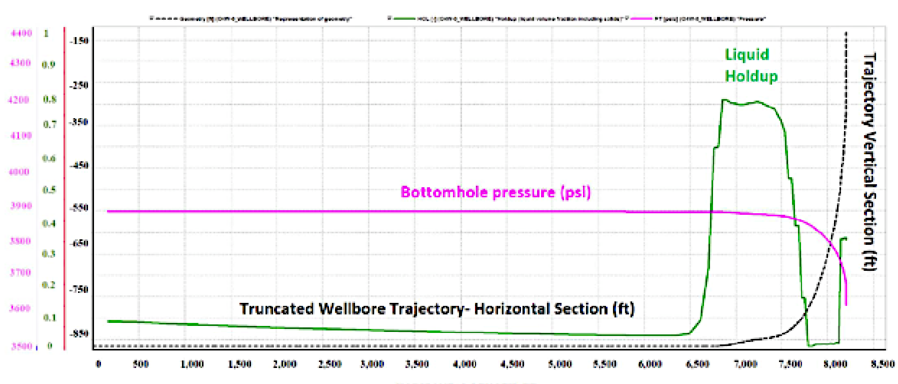


Figure 2.20. Truncated Trajectory
(Pradhan & Xiong, 2017)

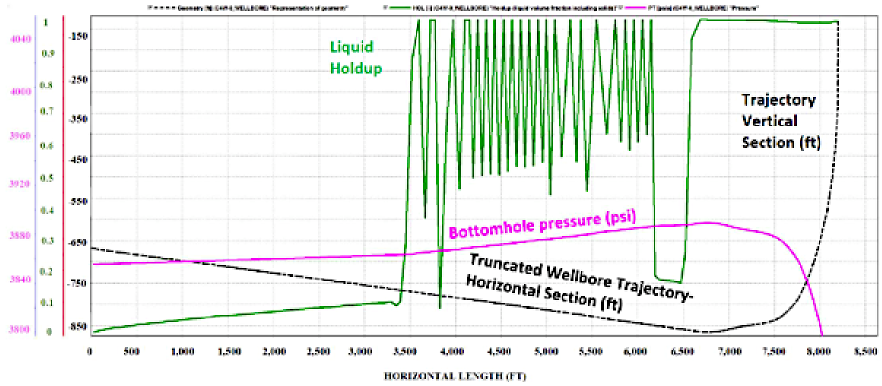


Figure 2.21. Toe-Up Trajectory
(Pradhan & Xiong, 2017)

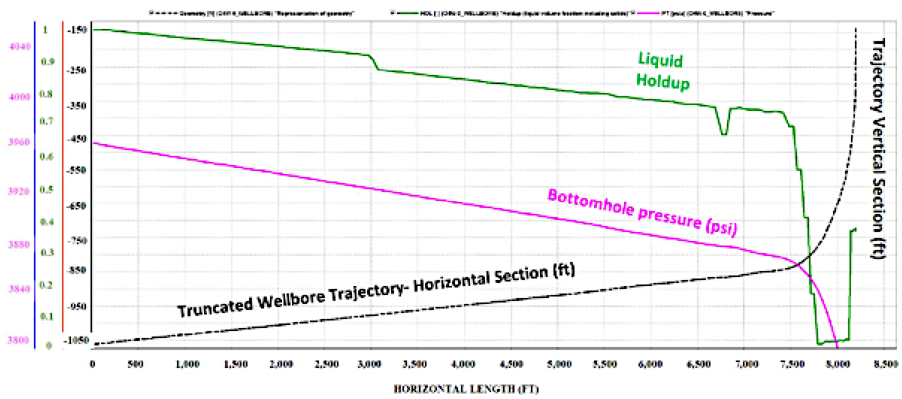


Figure 2.22. Toe-Down Trajectory
(Pradhan & Xiong, 2017)

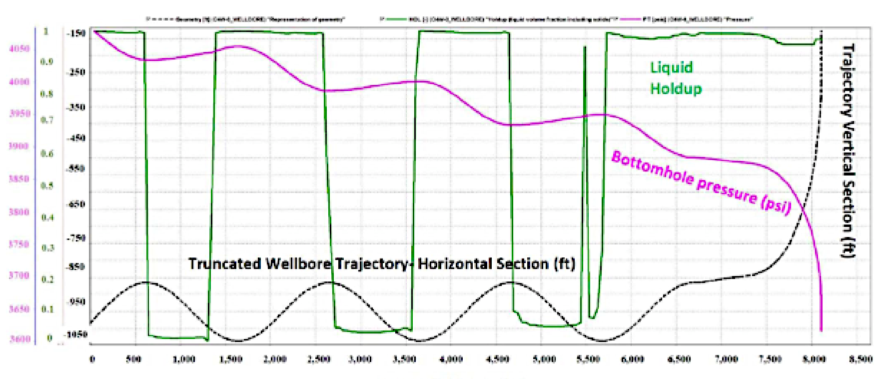


Figure 2.23. Undulated Trajectory
(Pradhan & Xiong, 2017)

The conclusions made by the authors reflect that the well trajectories play a decisive role in EUR. Many variables have to be considerate when production optimization matter the most (Pradhan & Xiong, 2017).

2.7.7. Dynamic Simulation To Assess Effectiveness Of Downhole Pump For Gas Well Deliquification. Starting from this study, the approach is focused on model flow simulations will be from a production perspective. Thus, the simulations are not going to use a CFD approach, but instead, they will pursue a transient multi-phase flow simulation using OLGA by Schlumberger.

(Yusuf, Veeken, & Hu, 2013) conducted research regarding gas well unloading procedures with a downhole pump.

The pressure at the reservoir decreases while producing. Whether gas or oil reservoir, the same behavior is expected. When reservoir pressure drops in a gas well, the reservoir has no longer enough energy to lift the gas to the surface. Small drops of oil and brine start to fall in the tubing. When this conduct persists, drops are accumulated forming a column of liquid that finally kills the gas well by stopping the gas flow up to the surface.

This practice is called gas well deliquification (GWD). According to the authors, GWD uses applications such as wellhead compression, velocity string, plunger lift, intermittent regulated production, and downhole pump.

It is recommended to run simulations for all the options before pursuing any road because each alternative represents a huge amount of money to be invested by operators. Thus, for this research, the authors' choice is downhole pump to evaluate its performance through transient multi-phase simulations.

Let us look at the survey and the completion for the gas well used in their research. Figure 2.24 represents the trajectory of the well (left) and the completion (right).

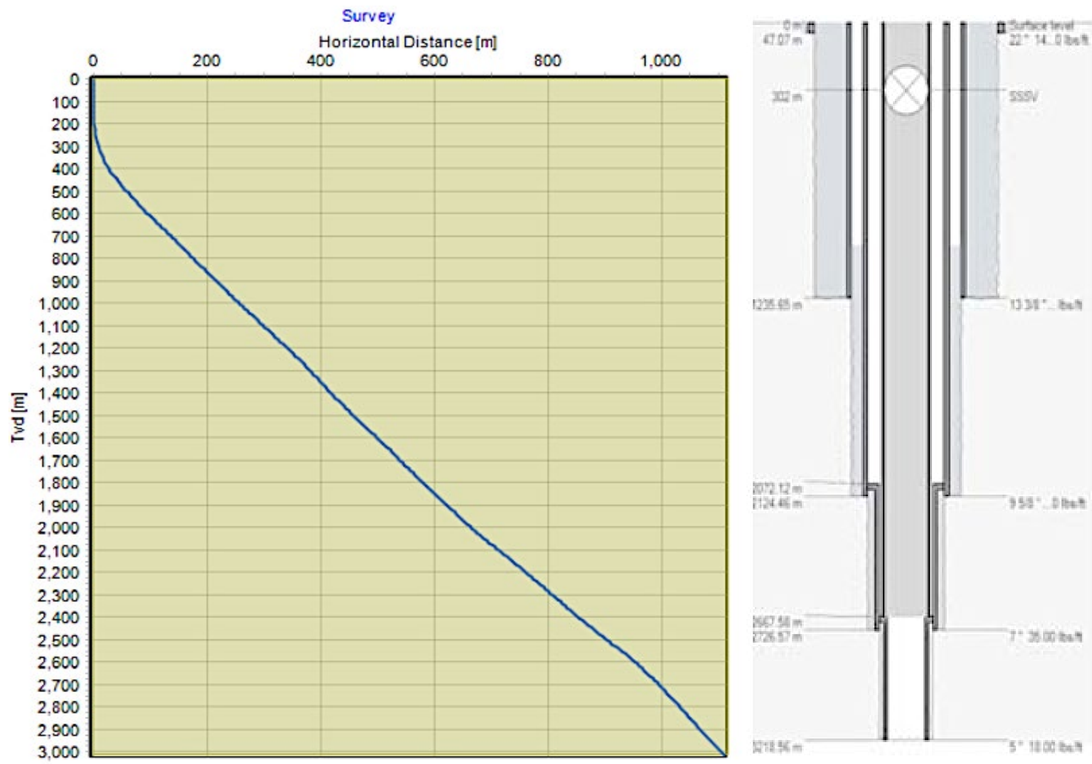


Figure 2.24. Survey And Completion
(Yusuf, Veeken, & Hu, 2013)

As the survey showed, the well has deviated. However, it does not contain any horizontal section.

The downhole pump is located at 20 m above the producing tubing toe.

The reservoir fluid composition is listed in Table 2.1. Using commercial PVT software, the reservoir conditions were characterized.

With the parameters already set up, the first part of the simulation showed the time when the gas well dies due to the column of liquid inside the tubing.

Table 2.1. Reservoir Fluid Composition
(Yusuf, Veeken, & Hu, 2013)

Component	Mol %	Mol. Wt.	Liquid Density [g/cc]
N2	3.60	28.0	
CO2	2.37	44.0	
C1	92.43	16.0	
C2	1.12	30.0	
C3	0.13	44.1	
iC4	0.03	58.1	
nC4	0.03	58.1	
iC5	0.02	72.1	
nC5	0.02	72.1	
C6	0.08	86.2	0.6640
C7+	0.15	190.0	0.9

Figure 2.25. shows that after 13 days the gas well is not producing any more (black line). The liquid holdup reaches 100% after eight days. The producing tubing is fulfilled with liquid (blue line).

The red line represents the pressure at the bottom of the wellbore whereas the green line stands for the total liquid content in the branch which reaches about 7.6 cubic meters in this example.

The authors made simulations for five different pump capacities to find the optimum pump capacity applied in their gas well. Let us look in one of their attempts.

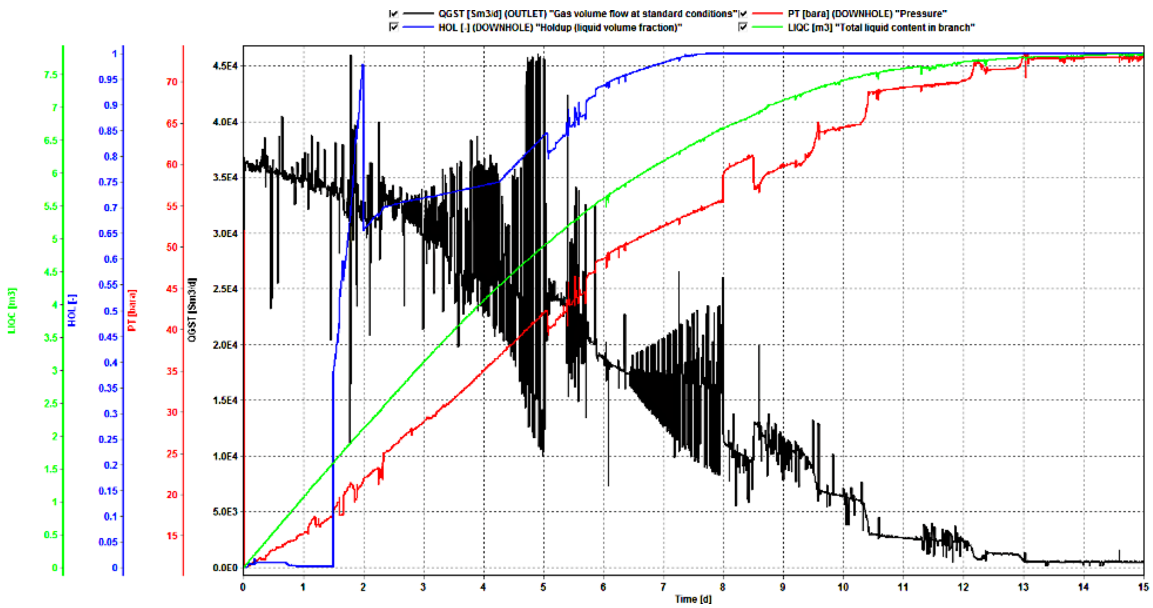


Figure 2.25. Behavior Of The Gas Well With Time
(Yusuf, Veeken, & Hu, 2013)

Figure 2.26 shows the unloading process by using a downhole pump. The blue line represents the hold-up (liquid volume fraction) which is reduced to zero after two days of using the downhole pump at four cubic meters per day as a pump-rate. The gas starts to produce as expected after the liquid is removed. After day number 7, the hold-up increases up to 75% in the branch lifting the pressure and the total liquid content in the branch. At this point, the downhole pump turns on again and remove the liquid after 12 hours. The process continues with the same trend.

A similar approach is used for other pump capacities which include 2, 1.5, 1 and 0.5 cubic meters per day. Some of the interesting conclusions, after this study was done, reveal that there are two ways to produce using a downhole pump, a cyclic manner, and steady rate. This is one of the first studies that highlight the value of transient multi-phase flow simulations.

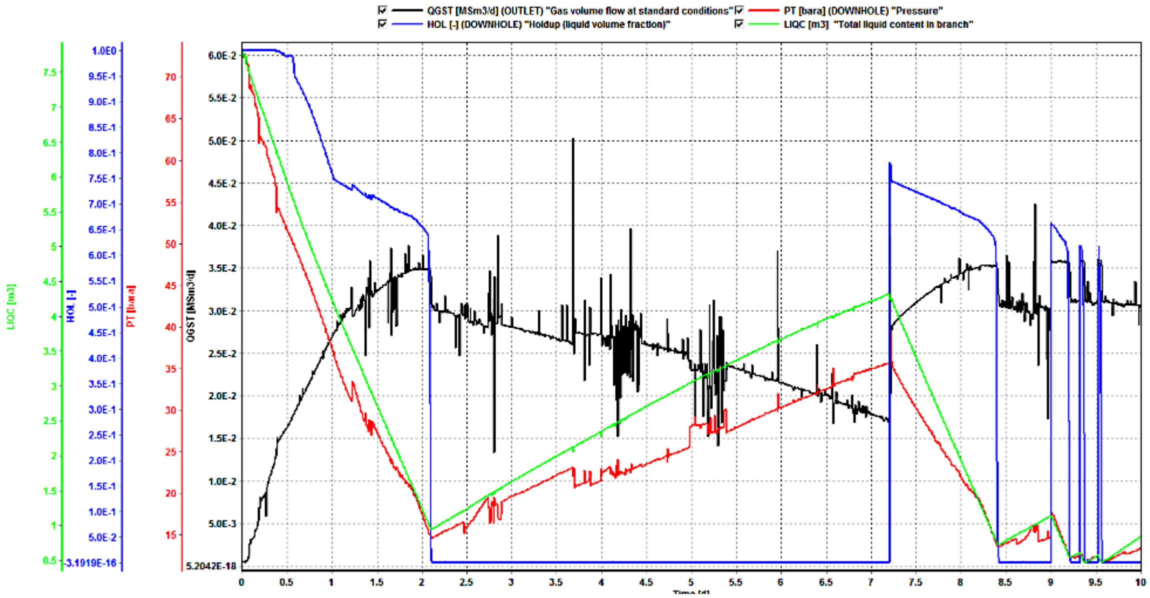


Figure 2.26. Unloading Gas Wells Using Downhole Pump
(Yusuf, Veeken, & Hu, 2013)

2.7.8. Well Spacing May Be Too Tight. Since most of the shale formations need to be hydraulic fractured, when it comes to drilling infill wells to produce more in a certain area. The probability of face a frac hit increases because of the well spacing in some areas might be too tight. Operators companies have realized that the child wells do not produce as much as the parent wells when both share an induced fracture between them.

Some of the studies have shown that predicting a frac hit is more or less impossible because there are too many unknown variables that describe the reservoir rock behavior under the surface. By using well logging and seismic techniques, engineers and geologists have calculated some of the behavior close to the wellbore, but the real question is what happens inside the rock many feet deeper. A Schlumberger research made in the Avalon shale showed that it is hard to find the optimum well spacing. Therefore, many operator companies have focused their efforts and resources to develop methodologies to mitigate the impacts of frac hits instead of researching ways to predict trajectories of frac hits.

As shown, frac hits can represent a serious issue for operators, and because of that, operators, now and then, share frac schedules to the companies that operate nearby to the wells being hydraulic stimulated to make them ready for eventual frac hits where this eventuality is a frequent outcome in shale formations. For instance, in Pennsylvania, the State Department of Environmental Protection considers proposing a regulation to oil companies that practice hydraulic fracture in shale formations to announce hydraulic fracture plans to the neighboring operators owing the fact that nowadays this practice is just a courtesy (Jacobs, Frac Hits Reveal Well Spacing May be Too Tight, Completion Volumes Too Large, 2017).

Figure 2.27 provides artwork for the origin of frac hits highlighting the needs to find the optimum well spacing to avoid frac hits in the first place.

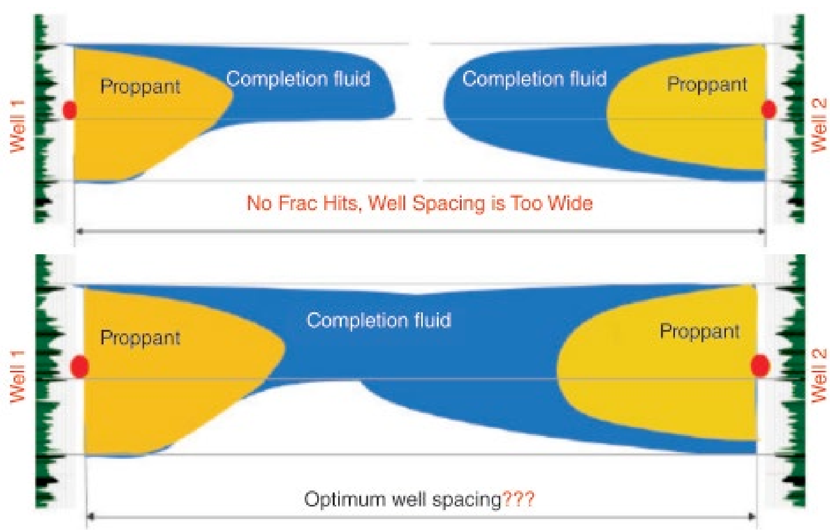


Figure 2.27. Frac Hit Origins
(Jacobs, Frac Hits Reveal Well Spacing May be Too Tight, Completion Volumes Too Large, 2017)

3. TRANSIENT MULTI-PHASE FLOW SIMULATION FOR THIS RESEARCH

The transient multi-phase flow simulation in this study was created using public available data recorded for a well identified in the Drilling Info database. At present, industry is not required to report frac hits in any state, so it was necessary to search Drilling Info and identify characteristic frac hit behavior in a pair of shale play wells.

This required identifying an existing shale play well in which production ceased for a short period, at the same time a new, closely spaced offset well was drilled and stimulated. This section describes the data identified and used in the OLGA modeling.

3.1. BASE CASE 1A1

The well identified for the base case model is an Eagle Ford Shale Play well located in the Hawk-Ville Field, La Salle County, Texas.

Figure 3.1. shows that gas and oil production in this well ceased for a short period, after a hydraulic fracture treatment took place in a new, offset water production increases significantly for a short period once production is re-established in the well. well.

This is characteristic behavior of a well that has been frac hit.

The offset well's production was used to calibrate the inflow performance equation in OLGA.

Figure 3.2. shows the monthly production for the well after the hydraulic fracturing treatment.

A normalized backpressure equation was used as the inflow model as this is a gas well, with some condensate and water production.

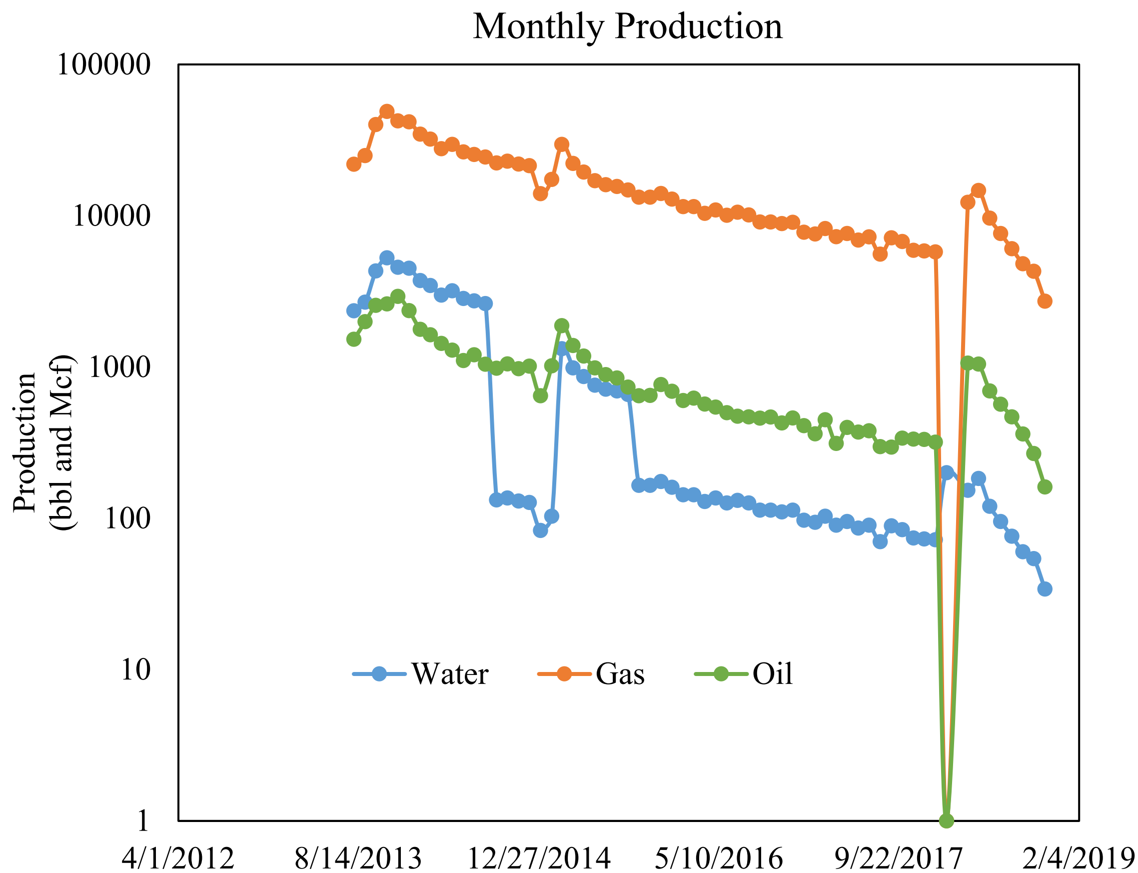


Figure 3.1. Monthly Production Parent Well

The normalized backpressure equation used in the modeling was:

$$q_0 = q_{0,max}\left[1 - \left(\frac{P_{wf}}{P_R}\right)^2\right]^n \tag{8}$$

$$q_0 = 90\left[1 - \left(\frac{P_{wf}}{4500}\right)^2\right]^{0.5} \tag{9}$$

This equation governs gas, condensate and water inflow when unloading reaches a point where the well can flow.

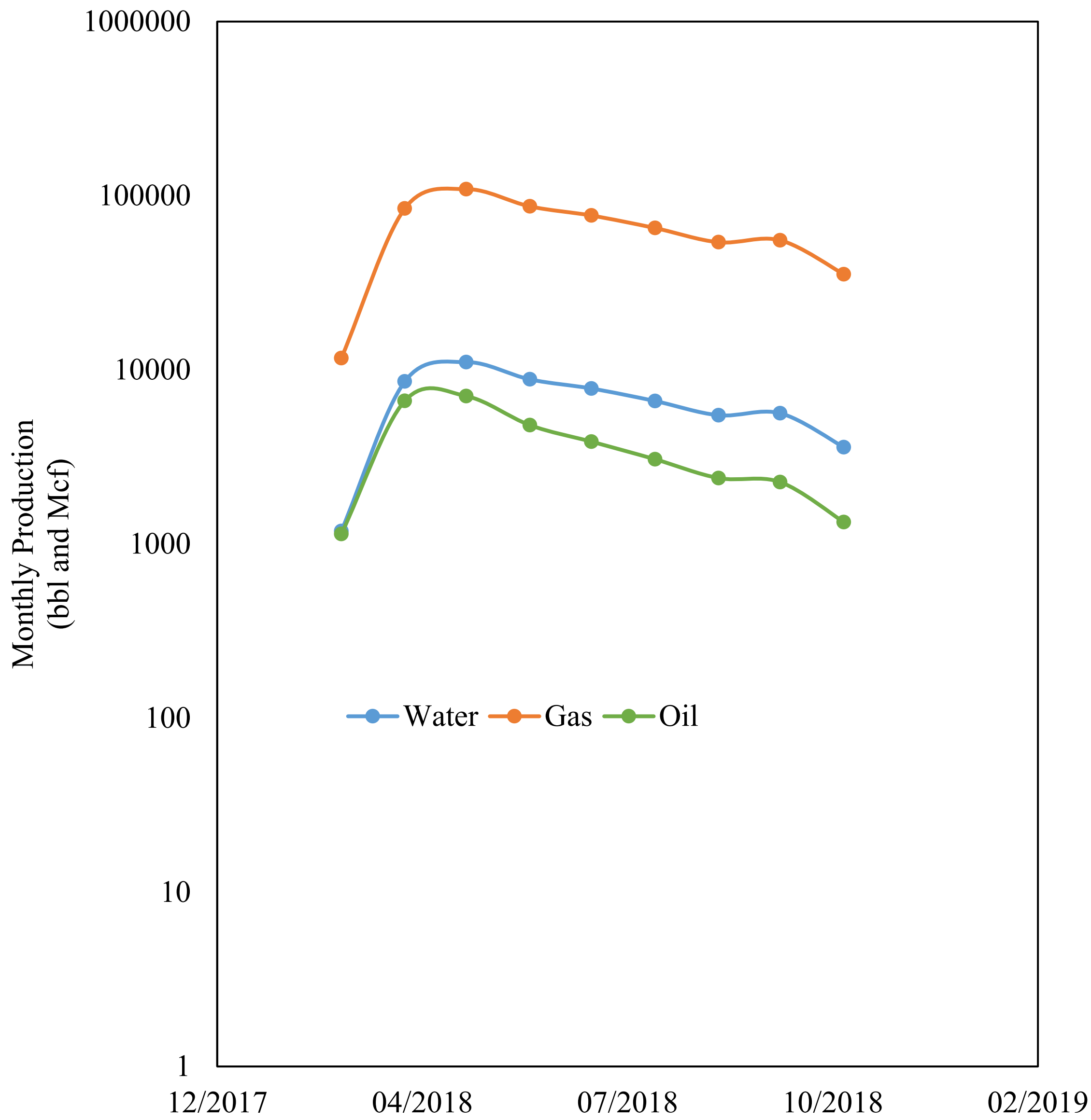


Figure 3.2. Monthly Production Child Well

3.1.1. Reservoir Fluid Composition. Figure 3.3. shows the hydrocarbon distribution within the Eagle Ford Play. The study well is located in la Salle County, within the liquids rich portion of the Eagle Ford Gas Play.

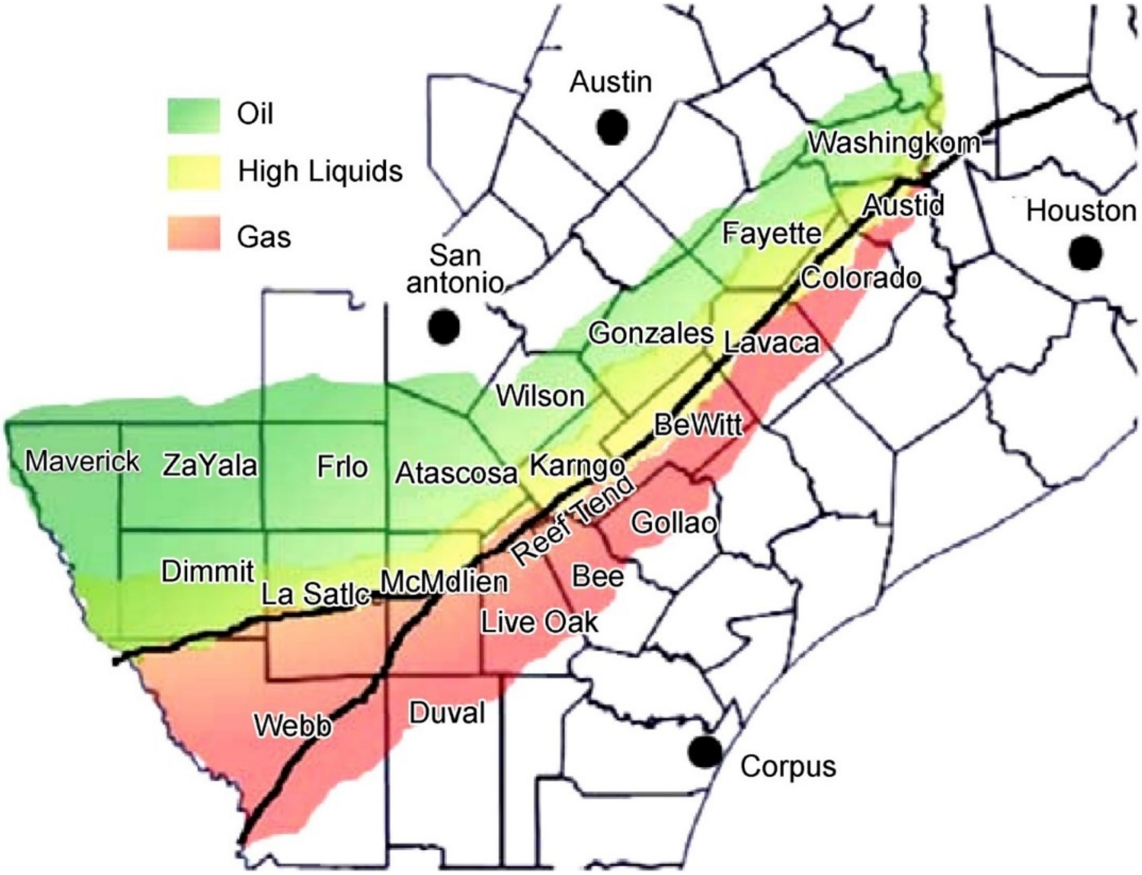


Figure 3.3. Eagle Ford Play Hydrocarbons Distribution
(Kamari, Li, & Sheng, 2018)

(Kamari, Li, & Sheng, 2018) presented the compositional data for the Eagle Ford Play, and these data were used in the modeling.

The oil compositional data for the Eagle Ford Play is listed in Table 3.1. and the condensate gas composition data is presented in Table 3.2.

Table 3.1. Oil Compositional Data For Eagle Ford Play

Composition	MW	Specific gravity	Acentric factor	Tc, R	Pc, psia	Vc, cft/lbM
C1	16.04	0.35	0.013	343.3	673.1	1.5658

Table 3.1. Oil Compositional Data For Eagle Ford Play (Cont.)

N2	28.01	0.808	0.04	227.2	492.3	1.4256
C2	30.07	0.48	0.0986	549.8	708.4	2.3556
C3	44.1	0.5077	0.1524	665.8	617.4	3.2294
CO2	44.01	0.8159	0.225	547.6	1071.3	1.5126
IC4	58.12	0.5631	0.1848	734.6	529.1	4.2127
NC4	58.12	0.5844	0.201	765.4	550.7	4.1072
IC5	72.15	0.6248	0.2223	828.7	483.5	4.9015
NC5	72.15	0.6312	0.2539	845.6	489.5	5.0232
NC6	86.18	0.6641	0.3007	914.2	439.7	5.9782
C7+	114.4	0.7563	0.3739	1060.5	402.8	7.4093
C11+	166.6	0.8135	0.526	1223.6	307.7	10.682
C15+	230.1	0.8526	0.6979	1368.4	241.4	14.739
C20+	409.2	0.9022	1.0456	1614.2	151.1	26.745

Table 3.2. Condensate Gas Compositional Data For Eagle Ford Play

Composition	MW	Specific gravity	Acentric factor	T_c, R	P_c, psia	V_c, cft/lbM
C_1	16.04	0.35	0.013	343.26	673.08	1.5658
N_2	28.01	0.808	0.04	227.16	492.32	1.4256
C_2	30.07	0.48	0.0986	549.774	708.35	2.3556
C_3	44.1	0.5077	0.1524	665.82	617.38	3.2294
CO_2	44.01	0.8159	0.225	547.56	1071.3	1.5126
IC_4	58.12	0.5631	0.1848	734.58	529.06	4.2127
NC_4	58.12	0.5844	0.201	765.36	550.66	4.1072

Table 3.2. Oil Compositional Data For Eagle Ford Play (Cont.)

IC_5	72.15	0.6248	0.2223	828.72	483.5	4.9015
NC_5	72.15	0.6312	0.2539	845.64	489.52	5.0232
NC_6	86.18	0.6641	0.3007	914.22	439.7	5.9782
C_{7+}	112	0.7527	0.3673	1051.39	408.59	7.261
C_{11+}	175	0.8201	0.5491	1245.9	296.89	11.2083
C_{15+}	210	0.8424	0.6435	1327.59	259.01	13.435
C_{20+}	250	0.8612	0.7527	1405.81	226.28	16.0488

With the previous data, (Kamari, Li, & Sheng, 2018) built the phase envelope diagram shown in Figure 3.4.

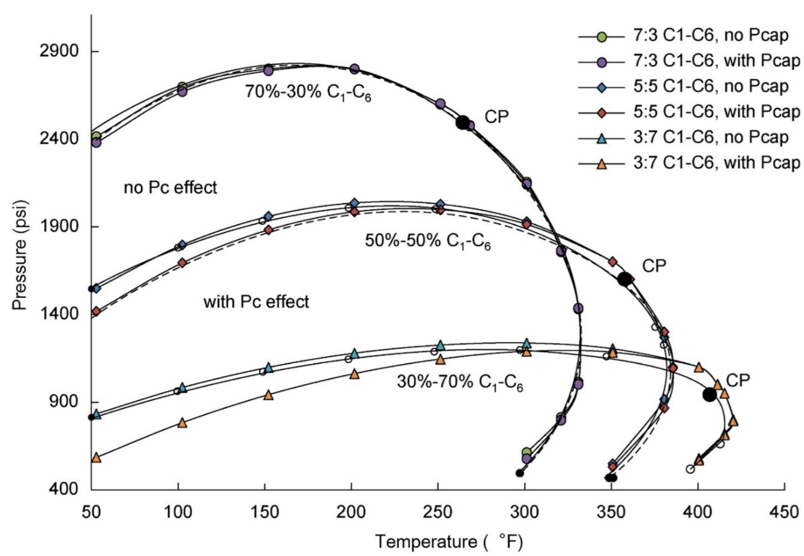


Figure 3.4. Eagle Ford Play Phase Envelope Diagram
(Kamari, Li, & Sheng, 2018)

These data were used in MultiFlash © by Schlumberger to describe the gas and liquid phases as they flow from the reservoir to the wellbore in the simulation.

3.1.2. Survey. The trajectory of the Eagle Ford well was used as the base case in the simulation model. Figure 3.5. illustrates the survey. As shown, the well's trajectory is formed by three different sections. The first section is the vertical section which reaches 5,000 ft vertical depth (TVD). The second section corresponds to the deviation build-up, with a measured depth of 10,271 ft. The final section shows the lateral section at 90 deg. This section reaches a length of 5,200 ft, approximately. Table 3.3. gives numerical information regarding the well survey, including, measured depths, true vertical depths, inclination, azimuth, north, east and horizontal distance.

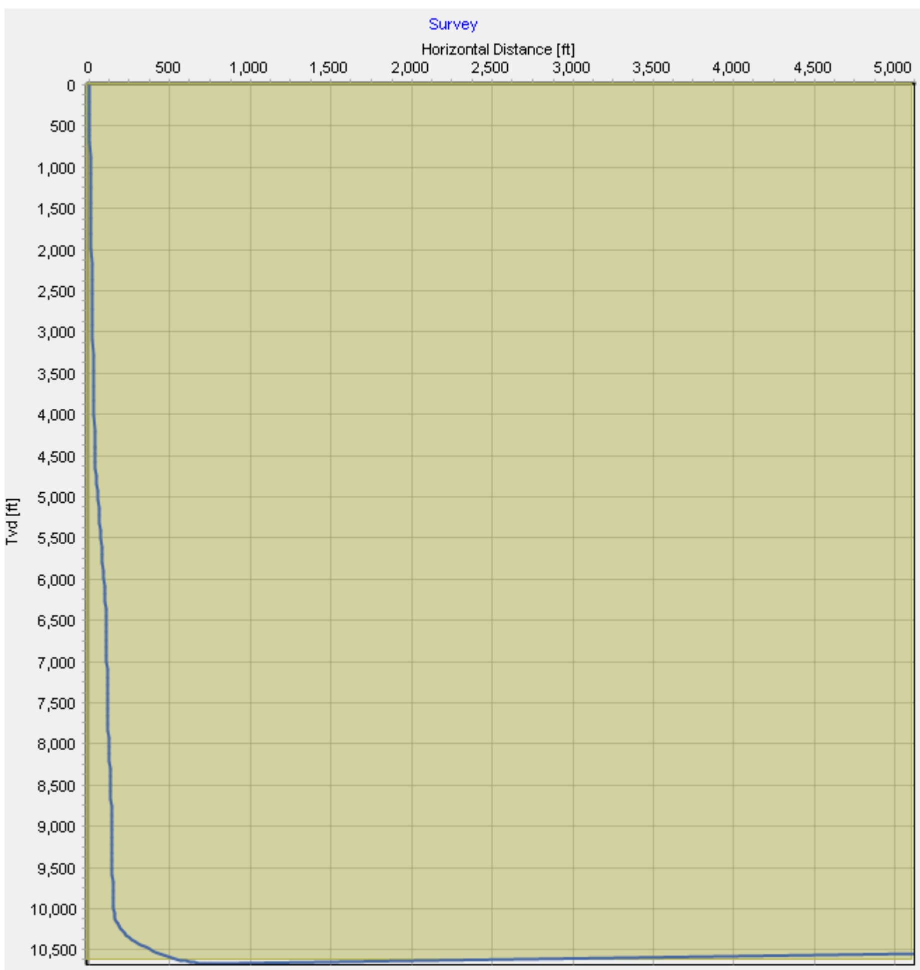


Figure 3.5. Case Study Well Survey

Table 3.3. Case Study Well Survey

MD [ft]	TVD [ft]	Inclination [DEGREE]	Azimuth [DEGREE]	North [ft]	East [ft]	Horizontal distance [ft]
0	0	0.23127	0	0	0	0
205	204.998	0.398468	0	0.8275	0	0.8275
358	357.995	0.341704	0	1.8915	0	1.8915
543	542.991	0.403834	0	2.9948	0	2.9948
605	604.99	0.401605	0	3.4318	0	3.4318
697	696.988	0.240429	0	4.0767	0	4.0767
881	880.986	0.305513	0	4.8488	0	4.8488
1066	1065.98	0.328814	0	5.8352	0	5.8352
1250	1249.98	0.350927	0	6.8912	0	6.8912
1435	1434.98	0.443008	0	8.0243	0	8.0243
1619	1618.97	0.487266	0	9.4469	0	9.4469
1804	1803.96	0.602253	0	11.0202	0	11.0202
1989	1988.95	0.555248	0	12.9648	0	12.9648
2173	2172.95	0.553104	0	14.7479	0	14.7479
2358	2357.94	0.554927	0	16.5337	0	16.5337
2542	2541.93	0.344291	0	18.3158	0	18.3158
2727	2726.93	0.250633	0	19.4275	0	19.4275
2912	2911.92	0.240429	0	20.2367	0	20.2367
3096	3095.92	0.247068	0	21.0088	0	21.0088
3281	3280.92	0.47097	0	21.8066	0	21.8066
3466	3465.91	0.650265	0	23.3273	0	23.3273
3650	3649.9	0.599892	0	25.4155	0	25.4155
3835	3834.89	0.498428	0	27.3524	0	27.3524

Table 3.3. Case Study Well Survey (Cont.)

4020	4019.88	0.502983	0	28.9617	0	28.9617
4204	4203.88	0.599596	0	30.577	0	30.577
4389	4388.87	0.50277	0	32.513	0	32.513
4409	4408.87	0.450292	0	32.6885	0	32.6885
4477	4476.86	0.49978	0	33.2229	0	33.2229
4569	4568.86	1.73403	0	34.0254	0	34.0254
4661	4660.82	2.89647	0	36.8093	0	36.8093
4754	4753.7	2.65061	0	41.5087	0	41.5087
4846	4845.6	2.49545	0	45.7633	0	45.7633
4941	4940.51	2.44968	0	49.8996	0	49.8996
5037	5036.42	2.30062	0	54.0028	0	54.0028
5133	5132.35	2.15005	0	57.8565	0	57.8565
5228	5227.28	2.05015	0	61.4206	0	61.4206
5324	5323.22	2.10085	0	64.8549	0	64.8549
5417	5416.16	2.09765	0	68.2642	0	68.2642
5513	5512.09	1.99928	0	71.778	0	71.778
5608	5607.03	1.94941	0	75.0923	0	75.0923
5704	5702.98	1.85003	0	78.3579	0	78.3579
5800	5798.93	1.65063	0	81.4572	0	81.4572
5895	5893.89	1.97884	0	84.1936	0	84.1936
5991	5989.83	2.49974	0	87.5086	0	87.5086
6086	6084.74	2.44898	0	91.652	0	91.652
6179	6177.66	2.35011	0	95.6258	0	95.6258
6271	6269.58	1.47272	0	99.3984	0	99.3984
6364	6362.55	0.549434	0	101.7885	0	101.7885

Table 3.3. Case Study Well Survey (Cont.)

6456	6454.54	0.49978	0	102.6707	0	102.6707
6548	6546.54	0.450914	0	103.4732	0	103.4732
6641	6639.54	0.503338	0	104.2051	0	104.2051
6733	6731.53	0.599456	0	105.0133	0	105.0133
6826	6824.53	0.599737	0	105.9863	0	105.9863
6918	6916.52	0.599737	0	106.9493	0	106.9493
7010	7008.52	0.600332	0	107.9123	0	107.9123
7102	7100.51	0.550334	0	108.8762	0	108.8762
7195	7193.51	0.49835	0	109.7695	0	109.7695
7287	7285.51	0.49835	0	110.5697	0	110.5697
7379	7377.5	0.450914	0	111.3699	0	111.3699
7472	7470.5	0.441394	0	112.1018	0	112.1018
7564	7562.5	0.550731	0	112.8105	0	112.8105
7656	7654.49	0.702486	0	113.6948	0	113.6948
7749	7747.49	0.9008	0	114.835	0	114.835
7841	7839.47	1.15246	0	116.2814	0	116.2814
7933	7931.46	1.34597	0	118.1318	0	118.1318
8026	8024.43	1.42919	0	120.3163	0	120.3163
8118	8116.4	1.49866	0	122.6109	0	122.6109
8210	8208.37	1.40122	0	125.017	0	125.017
8303	8301.34	1.25019	0	127.2912	0	127.2912
8395	8393.32	1.10148	0	129.2985	0	129.2985
8487	8485.3	0.999846	0	131.067	0	131.067
8580	8578.29	0.999213	0	132.6898	0	132.6898
8672	8670.27	0.898817	0	134.2942	0	134.2942

Table 3.3. Case Study Well Survey (Cont.)

8764	8762.26	0.60122	0	135.7374	0	135.7374
8857	8855.26	0.30459	0	136.7132	0	136.7132
8949	8947.26	0.138812	0	137.2023	0	137.2023
9041	9039.26	0.202353	0	137.4252	0	137.4252
9134	9132.26	0.350355	0	137.7536	0	137.7536
9226	9224.25	0.450914	0	138.3162	0	138.3162
9319	9317.25	0.550731	0	139.0481	0	139.0481
9411	9409.25	0.70224	0	139.9324	0	139.9324
9503	9501.24	0.901592	0	141.06	0	141.06
9595	9593.23	0.999846	0	142.5076	0	142.5076
9688	9686.21	1.1005	0	144.1304	0	144.1304
9780	9778.2	1.35194	0	145.8974	0	145.8974
9872	9870.17	1.70056	0	148.068	0	148.068
9965	9963.13	2.00083	0	150.8279	0	150.8279
9996	9994.11	2.20019	0	151.9102	0	151.9102
10057	10055.1	3.8343	0	154.2521	0	154.2521
10088	10086	7.49534	0	156.3251	0	156.3251
10119	10116.7	11.8725	0	160.3689	0	160.3689
10149	10146.1	15.8813	0	166.5409	0	166.5409
10180	10175.9	17.8505	0	175.0239	0	175.0239
10211	10205.4	18.4002	0	184.5265	0	184.5265
10242	10234.8	19.7571	0	194.3117	0	194.3117
10272	10263.1	22.7738	0	204.4527	0	204.4527
10303	10291.6	26.7216	0	216.4526	0	216.4526
10334	10319.3	30.8211	0	230.392	0	230.392

Table 3.3. Case Study Well Survey (Cont.)

10365	10346	34.4602	0	246.2751	0	246.2751
10395	10370.7	37.3541	0	263.2501	0	263.2501
10426	10395.3	39.8534	0	282.059	0	282.059
10457	10419.1	42.6586	0	301.9246	0	301.9246
10488	10441.9	45.0012	0	322.9311	0	322.9311
10519	10463.9	45.9	0	344.8519	0	344.8519
10549	10484.7	46.5502	0	366.3957	0	366.3957
10580	10506	48.3544	0	388.901	0	388.901
10611	10526.6	51.054	0	412.0663	0	412.0663
10642	10546.1	54.1562	0	436.1762	0	436.1762
10673	10564.3	57.4038	0	461.3053	0	461.3053
10703	10580.5	59.9518	0	486.58	0	486.58
10734	10596	62.1018	0	513.4137	0	513.4137
10765	10610.5	64.3017	0	540.8109	0	540.8109
10796	10623.9	67.0031	0	568.7447	0	568.7447
10826	10635.6	71.3072	0	596.3605	0	596.3605
10857	10645.6	75.9026	0	625.7253	0	625.7253
10888	10653.1	79.752	0	655.7916	0	655.7916
10919	10658.6	83.0506	0	686.2971	0	686.2971
10949	10662.3	86.1506	0	716.0767	0	716.0767
10980	10664.4	89.95	0	747.0068	0	747.0068
11011	10664.4	91.6754	0	778.0067	0	778.0067
15345	10537.7	0	0	5110.154	0	5110.154

3.1.3. Completion Design. A common shale play completion design was used in the simulation. This completion design is shown in Figure 3.7.

As seen in Figure 3.6., this completion has a 9 5/8in. 53.50lbs/ft casing tubing that sets at 4460ft depth with an inner diameter of 8.535in., an outer diameter of 9.625in.

The second part of this completion has a 5 ½in. 23.00lbs/ft casing tubing, set at 15,325ft depth. The outer diameter is 5.5in. and the inner diameter is 4.548in.

The production tubing reaches 9.606ft with a tubing-casing of 2 3/8in. 2.64lbs/ft. The inner diameter is 2.157in. and the outer diameter is 2.375in.

The perforations are located from 12000 ft to 15325 ft.

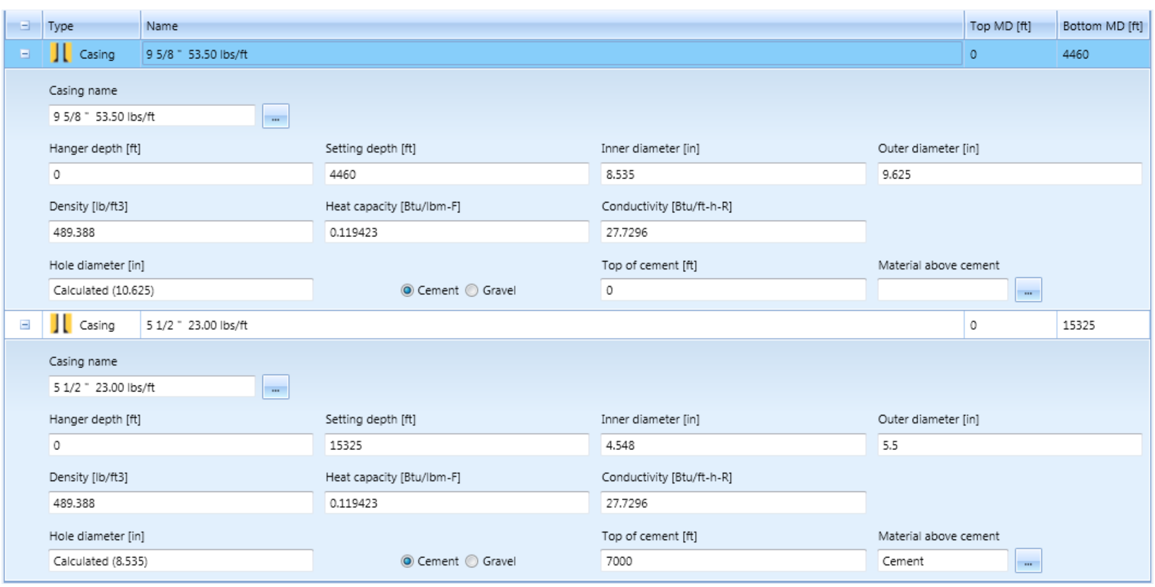


Figure 3.6. Case Study 1A1 Completion Design In Detail

3.1.1. Equipment. At this time, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

The valve measures the flow rate, type of flow, flow regime, and flow pressure.

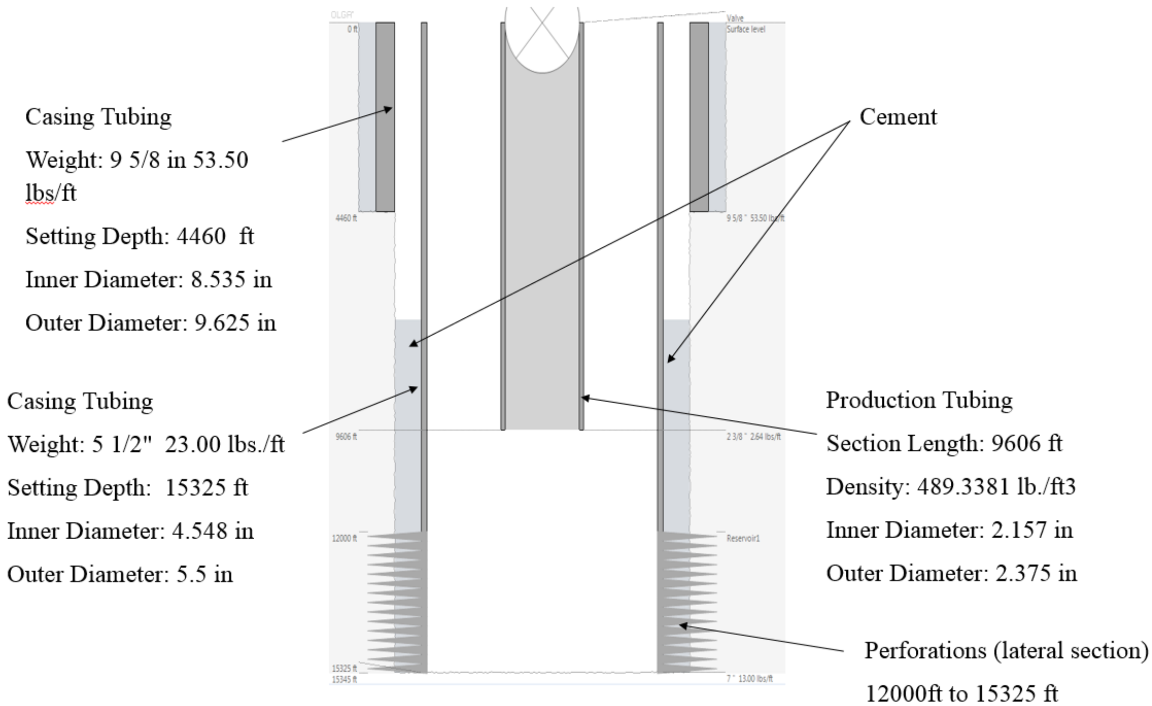


Figure 3.7. Base Case Completion Design Illustration

3.1.2. Pre-Processing Calculation. In OLGA, after defining the survey, completion design and the equipment, it is required to set up the initial boundary conditions to run a pre-processing calculation. In other words, at this point, field-data information such as ambient temperature, reservoir pressure, reservoir temperature, level of the frac hit liquid are going to be set up in this model for simulation.

3.1.3. Temperature. Two main values, ambient and reservoir temperature, are required in the model. In this case, the ambient temperature is 60 °F whereas the reservoir temperature is 285 °F. A linear temperature profile is assumed.

Figure 3.8. illustrates the temperature profile in function of the true vertical depth.

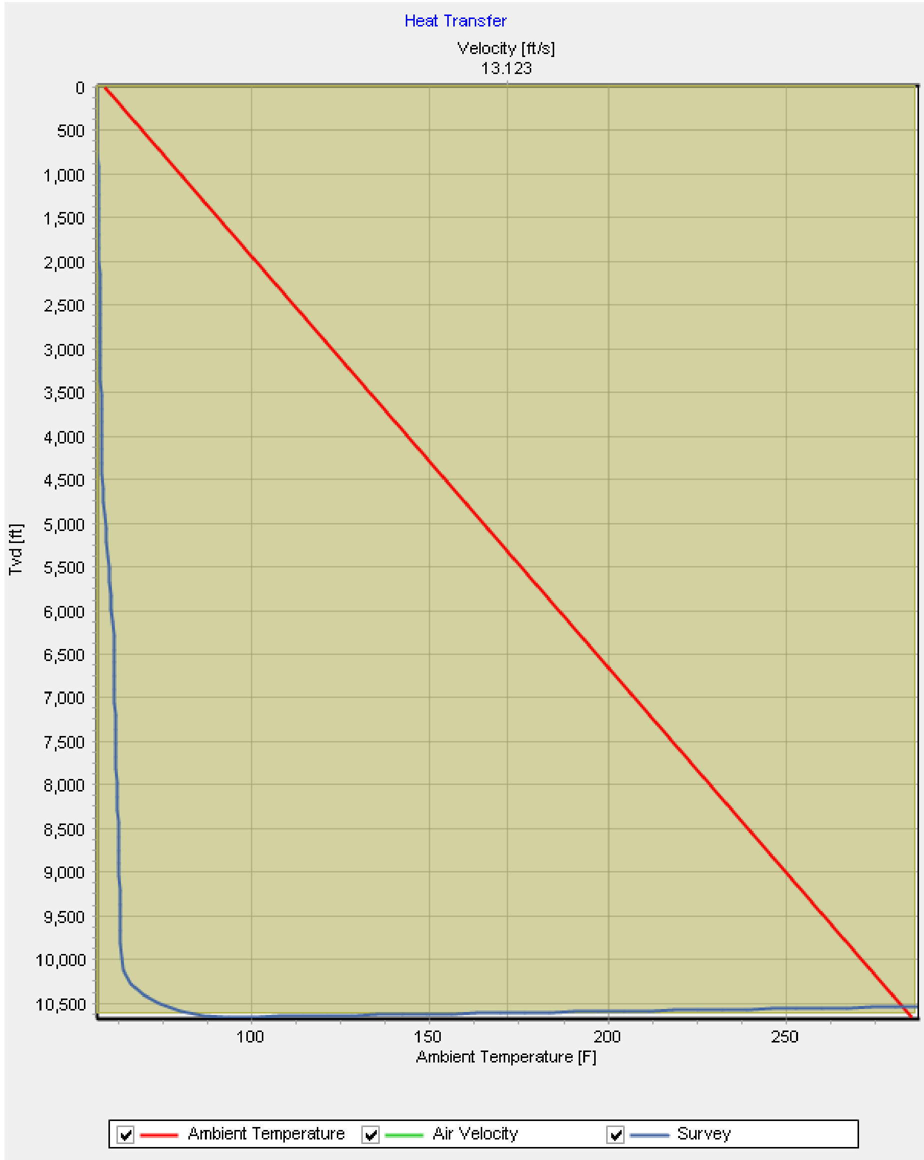


Figure 3.8. Base Case Pre-Processing Input Temperatures

However, the temperature profile is not accurate at this point. The reason is that the temperature profile cannot be a straight line when convection and diffusion are presented inside the wellbore. Hence, it is required to run a pre-processing calculation at the beginning, so that OLGA can calculate the real physical boundary conditions moving from a steady-state calculation into a transient calculation. In the following sections, the temperature profile will have a different profile after running the pre-processing calculations.

3.1.4. Fluid Level Initial Conditions. The column of liquid does not represent the real column at the field. The virtual column at the field will be calculated in OLGA in the initialization process.

In this point, if the real level of liquid is known in the field, the simulation has to be re-adjusted using an iterative mode until the output reaches the real level of fluid before proceeding with the unloading simulation. Figure 3.9 presents details about the level of fluid for the pre-processing calculations. Figure 3.10 shows an illustration of the column of fluid.

Casing/Liner/Open Hole

MD [ft]	TVD [ft]	Temperature [F]	Pressure [psia]	Massflow [lb/s]	Drilling fluid
0	0	59	0	0	2 (Nitrogen....
5100	5099.37	59	0	0	3 (Brine.tab)
15325	10538.3	59	0	0	3 (Brine.tab)

Tubing

MD [ft]	TVD [ft]	Temperature [F]	Pressure [psia]	Massflow [lb/s]	Drilling fluid
0	0	59	0	0	2 (Nitrogen....
5100	5099.37	59	0	0	3 (Brine.tab)
9606	9604.23	59	0	0	3 (Brine.tab)

Figure 3.9. Pre-Processing Initial Conditions Fluid Level Details

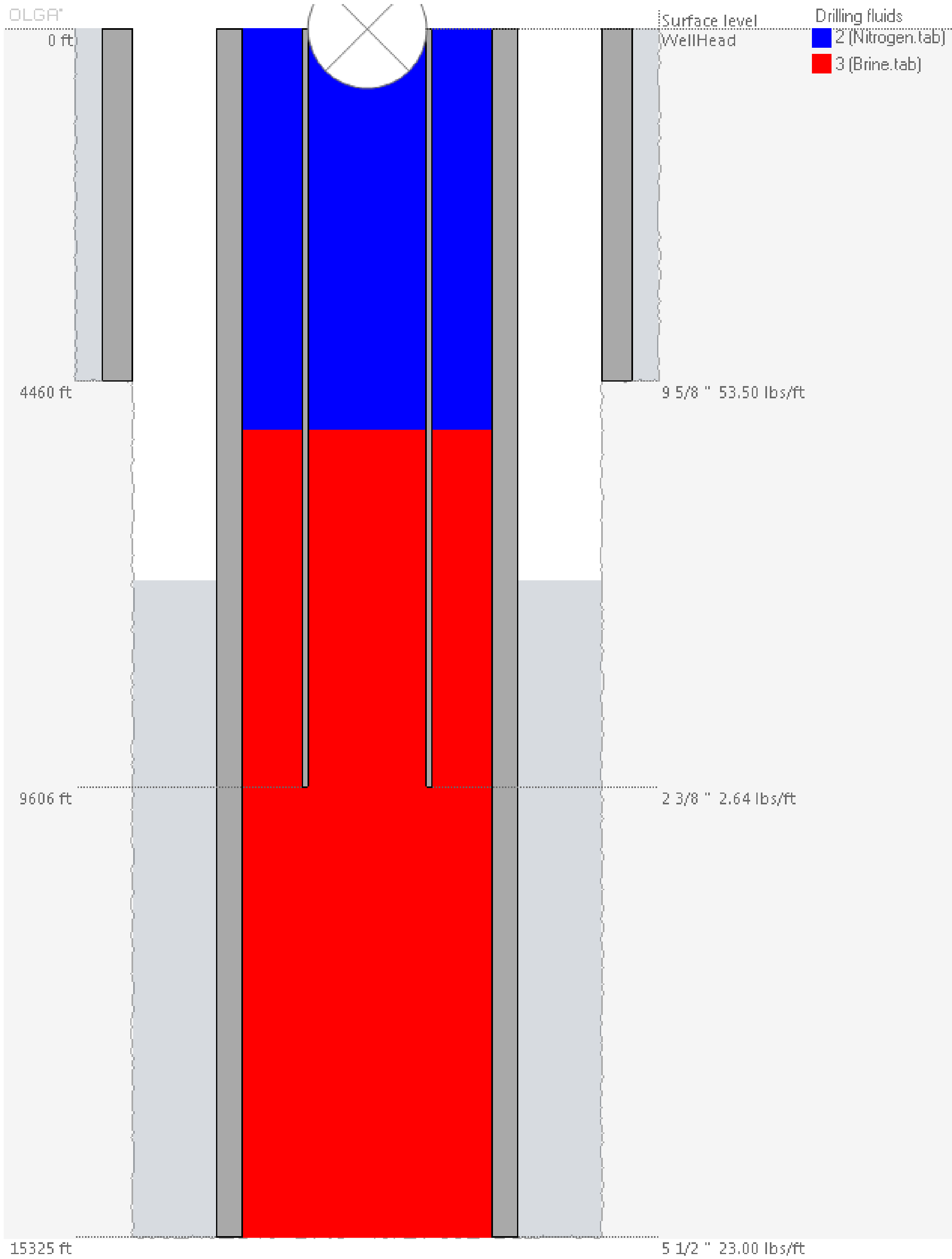


Figure 3.10. Pre-Processing Initial Conditions Fluid Level Illustration

The blue fluid represents the nitrogen whereas the red fluid is brine. Initially, the nitrogen is in the annulus and tubing string in the upper section of the well. this is an assumption that OLGA makes.

Temperature and Pressure. Under initial conditions, temperature and pressure must be defined. Table 3.4. presents the values used in this study.

Table 3.4. Initial Conditions

	Reservoir	Wellhead
Temperature [°F]	285	60
Pressure [psia]	4500	40

3.1.5. Pre-Processing Results. In this section, the following results will be taken as the input (RESTARTFILE) for the unloading process.

Prior to the unloading process, it is necessary to review the pre-processing results of the simulation.

The first variable to be discussed is pressure. Figure 3.11 plots the pressure profile for the base case after the first 5 hours of stabilization.

It is expected that the profile is due to the hydrostatic pressure created by the column of liquid. Again, this profile will change during the transient multiphase flow simulation in the next section. The second variable is temperature. Figure 3.12 shows the temperature profile after the first 5h of pre-processing simulation.

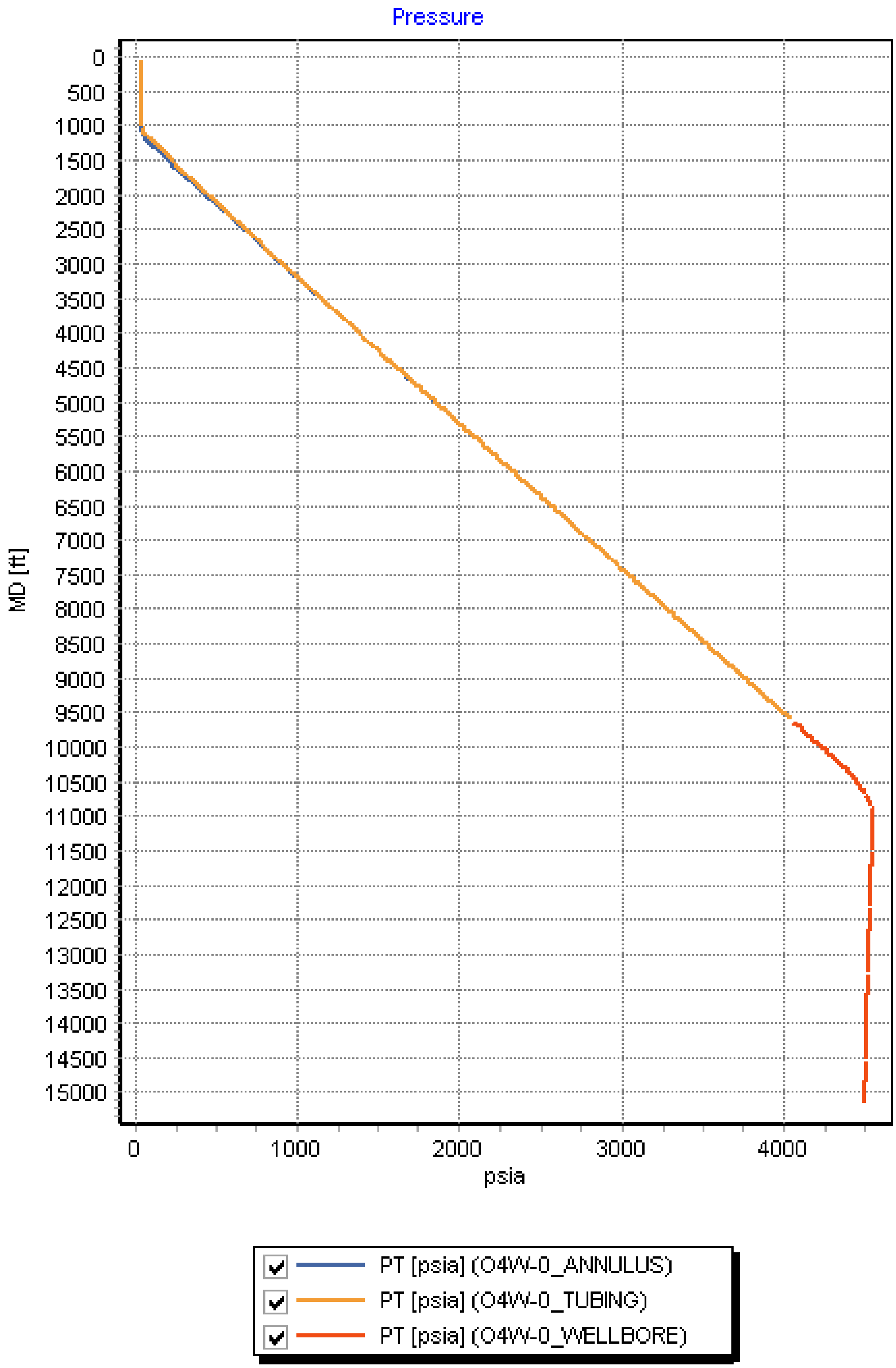


Figure 3.11. Case Study Pressure Pre-Processing Model Time = 5h

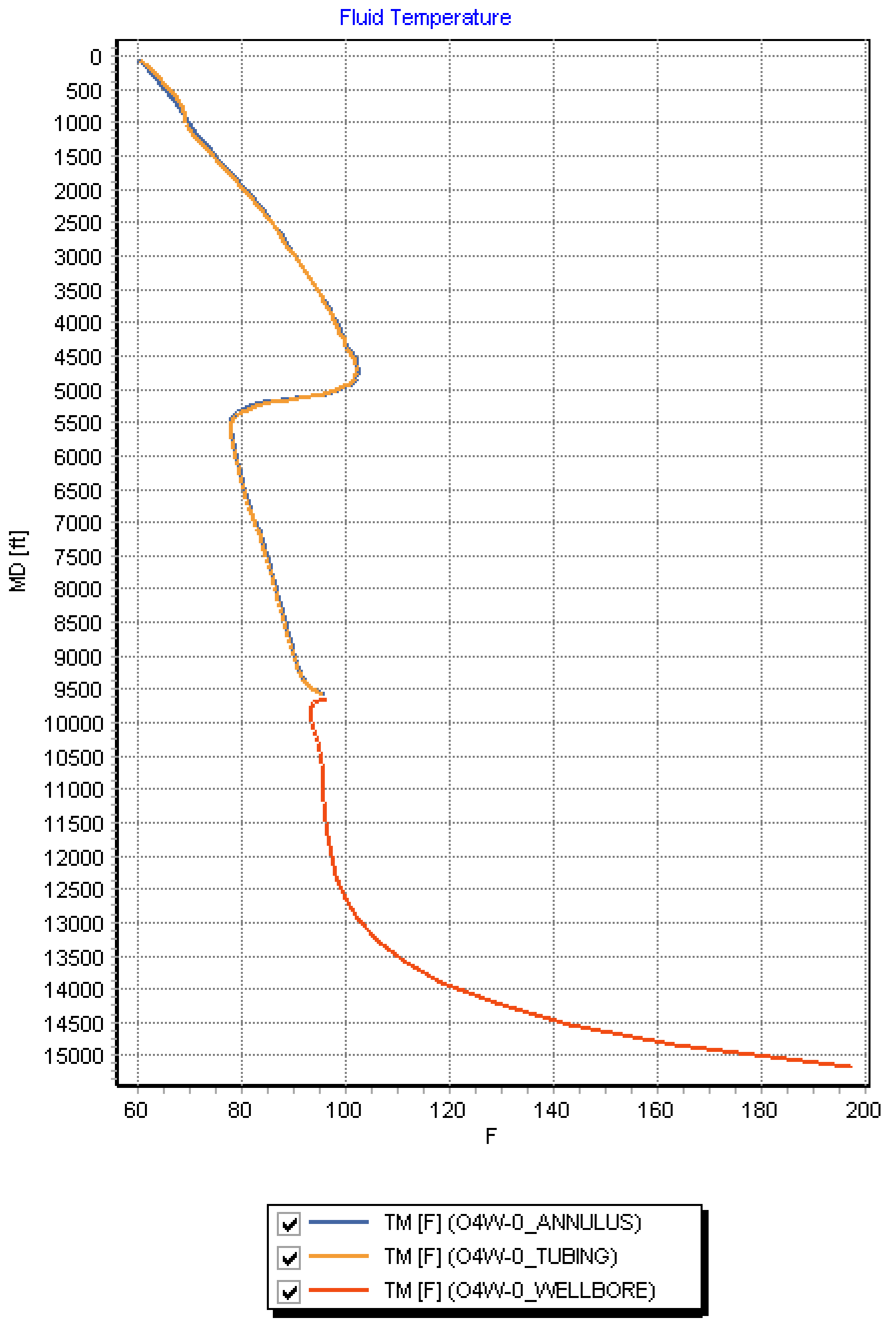


Figure 3.12. Temperature Pre-Processing Model Time = 5h

The third variable to be discussed is hold-up or volume fraction liquid at any point. As mentioned before, if the level of the column of liquid is known in the field, it is required to adjust the simulation until the stabilized results achieve the real level of the column of liquid.

Figure 3.13 shows the hold-up profile at time zero, which means that the level of liquid is not being affected by the reservoir pressure and the surface pressure.

Because this is not true, Figure 3.14 represents the actual level of the column of liquid after the reservoir pressure, and the surface pressure is being considered.

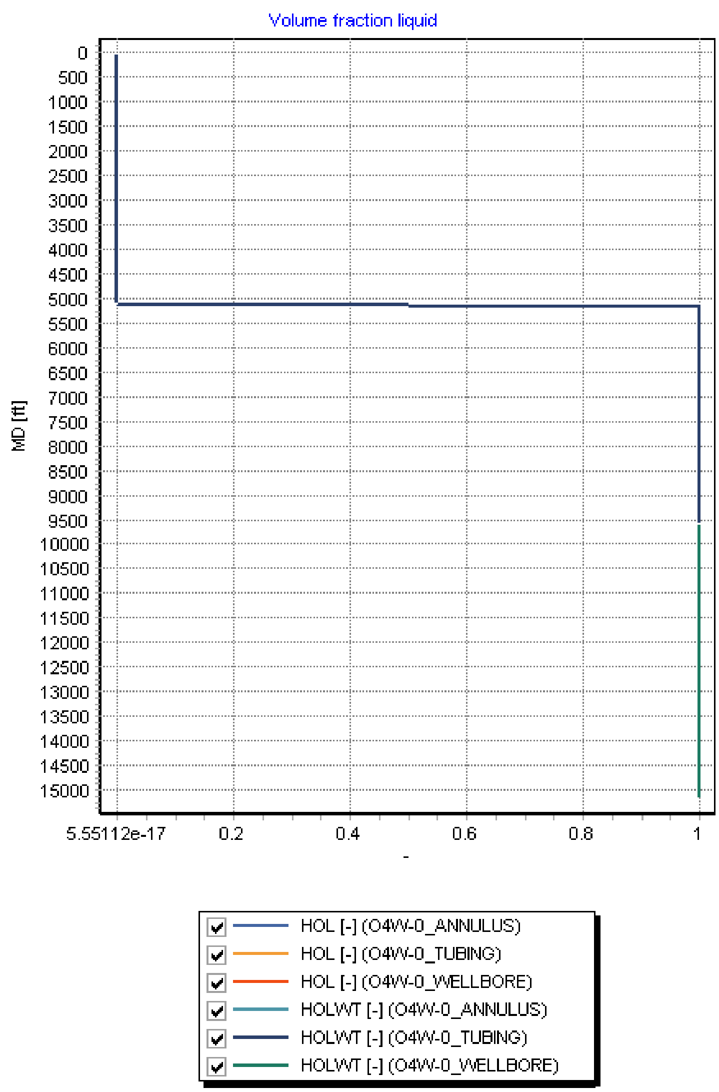


Figure 3.13. Hold-Up Pre-Processing Model Time Zero

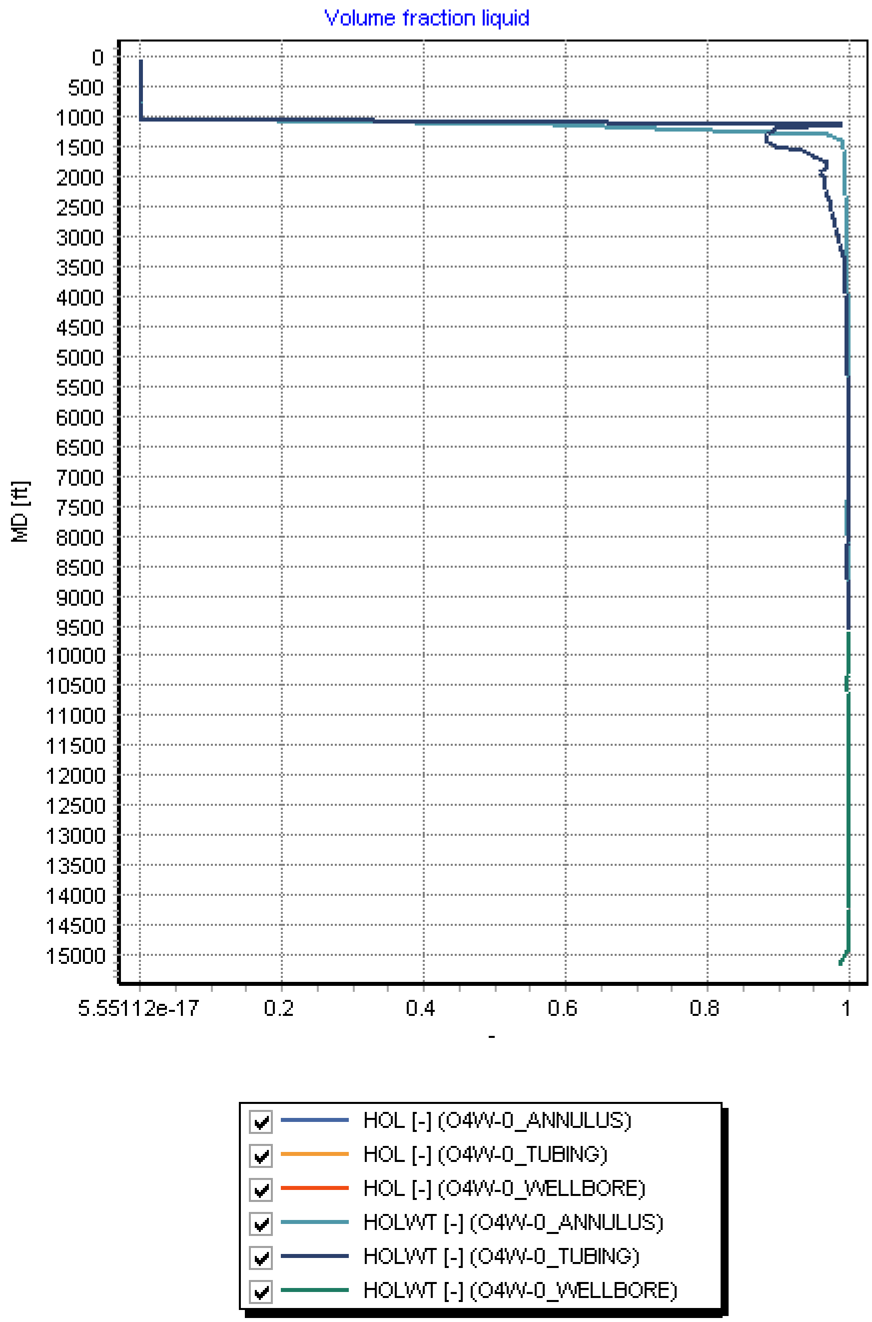


Figure 3.14. Hold-Up Stabilized (Time=5h) Pre-Processing Model

In order words, to match the real level of liquid at the field, the model will have to be adjusted in the Input Level in OLGA until it reaches the Real Level of liquid in the pre-processing simulation. Figure 3.15 shows the difference between the input level and the real level after calculation.

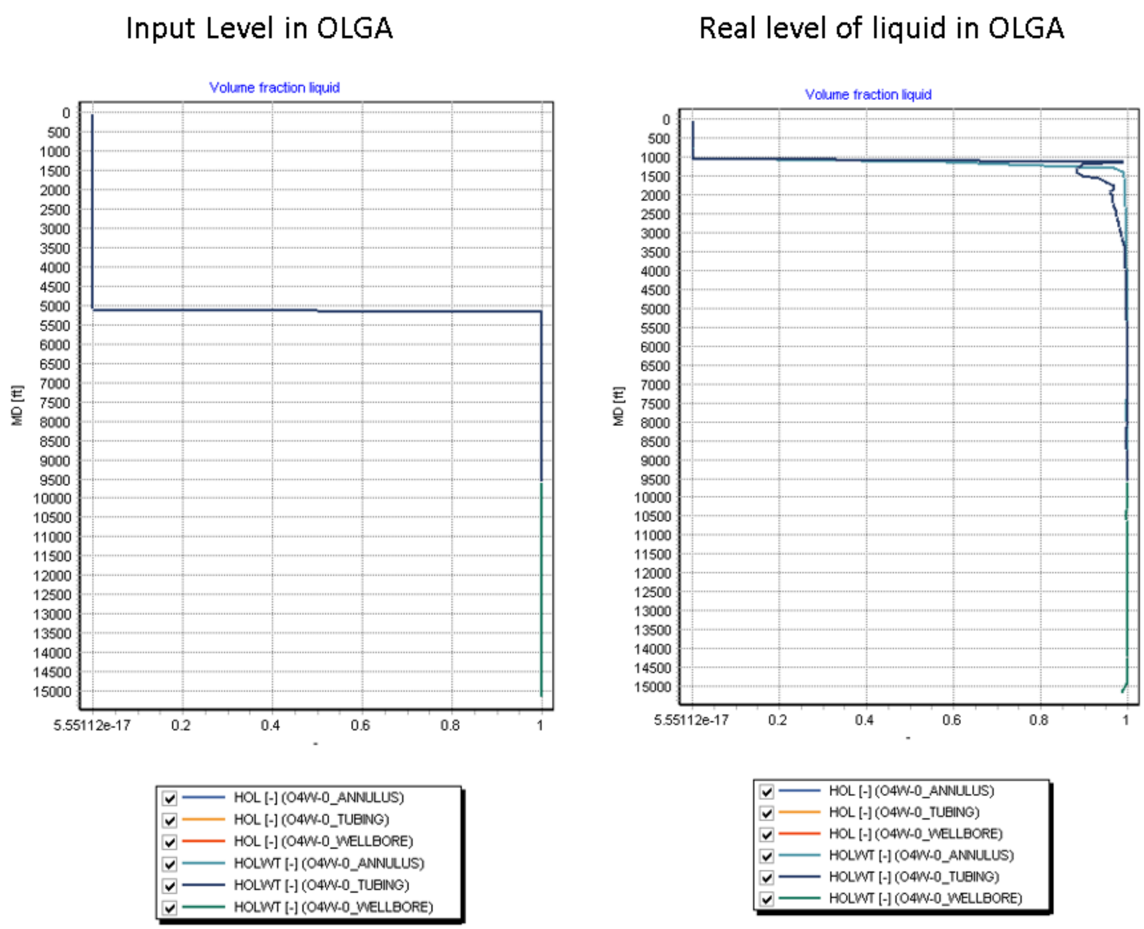


Figure 3.15. Input Level Vs. Real Level In OLGA

To better understand this situation, Figure 3.16 shows the hold-up in the lateral, annulus and tubing.

Where water (brine) is the blue liquid and gas is the dark orange liquid (OLGA consider gas and oil under the same label). The water phase is the frac hit liquid in this case.

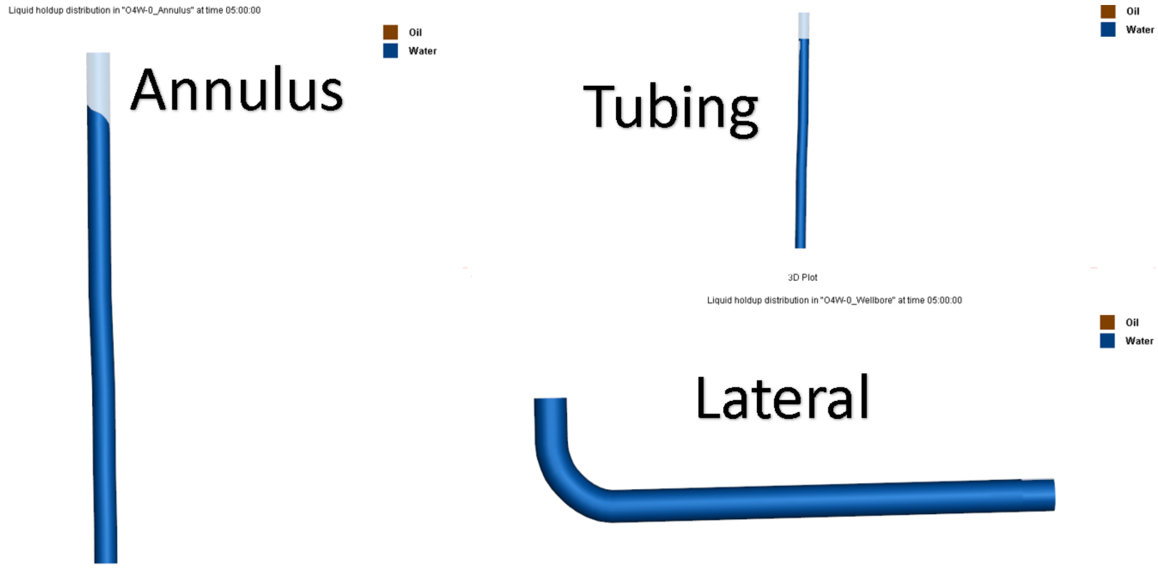


Figure 3.16. Real Level Of The Frac Fluid, At Time = 5h

3.1.6. Case Study Unloading Simulation. Once the pre-processing simulation reaches equilibrium for the steady-state condition, the unloading simulation process takes place. The following sub-sections describe some variables that show how the well is being unloaded.

3.1.7. Unloading Simulation Model. Figure 3.17 describes the model for the unloading base case in OLGA. As shown, there is a surface nitrogen source and a reservoir contact added to the pre-processor diagram.

The orange lines represent the direction of the nitrogen injection through the annulus, whereas the blue lines represent the frac hit liquid (brine) coming up through the tubing to the surface.

For the base case, the unloading process is run for 5 hours. Figure 3.18 shows the new components added to the pre-processing model. The new components are highlighted in red.

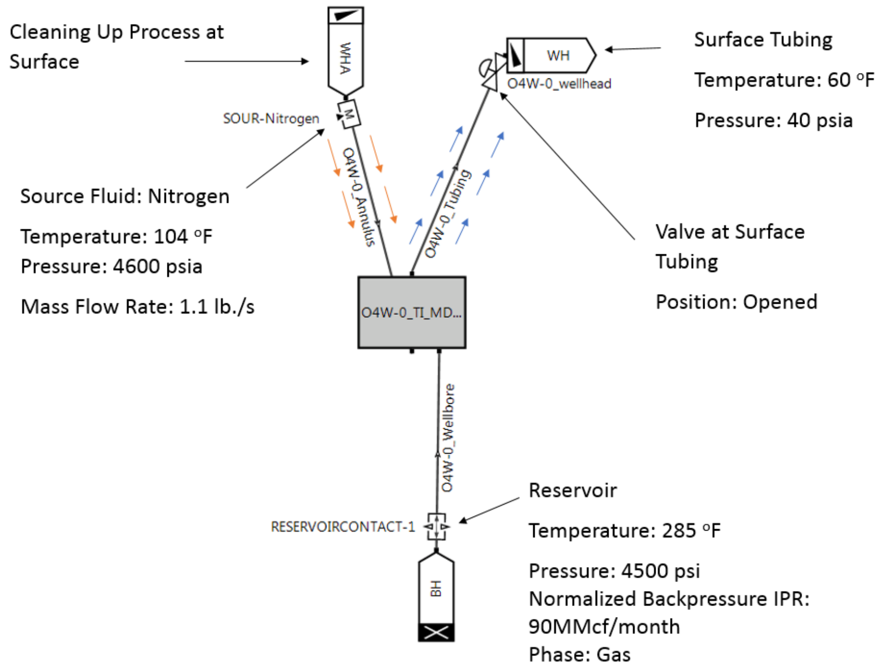


Figure 3.17. OLGA Cleaning Simulation Model

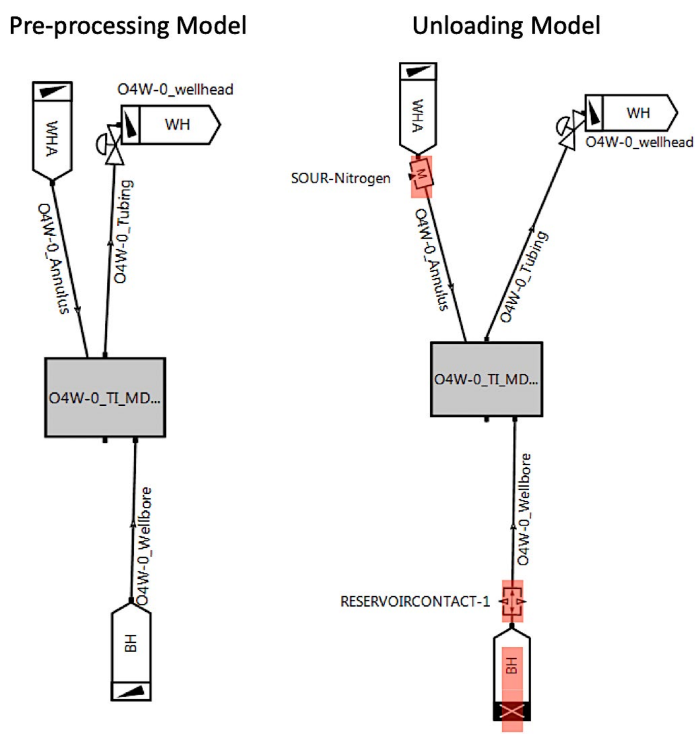


Figure 3.18. Pre-Processing Vs. Unloading Model

3.1.7.1. Nitrogen source. Nitrogen is injected at 4600 psia, 104 °F, with a mass flow of 1.1 lb./s for 60 min, as shown in Figure 3.19. The valve is being opened in the first 60 sec as shown in Figure 3.20 and remains open until the end of the simulation.

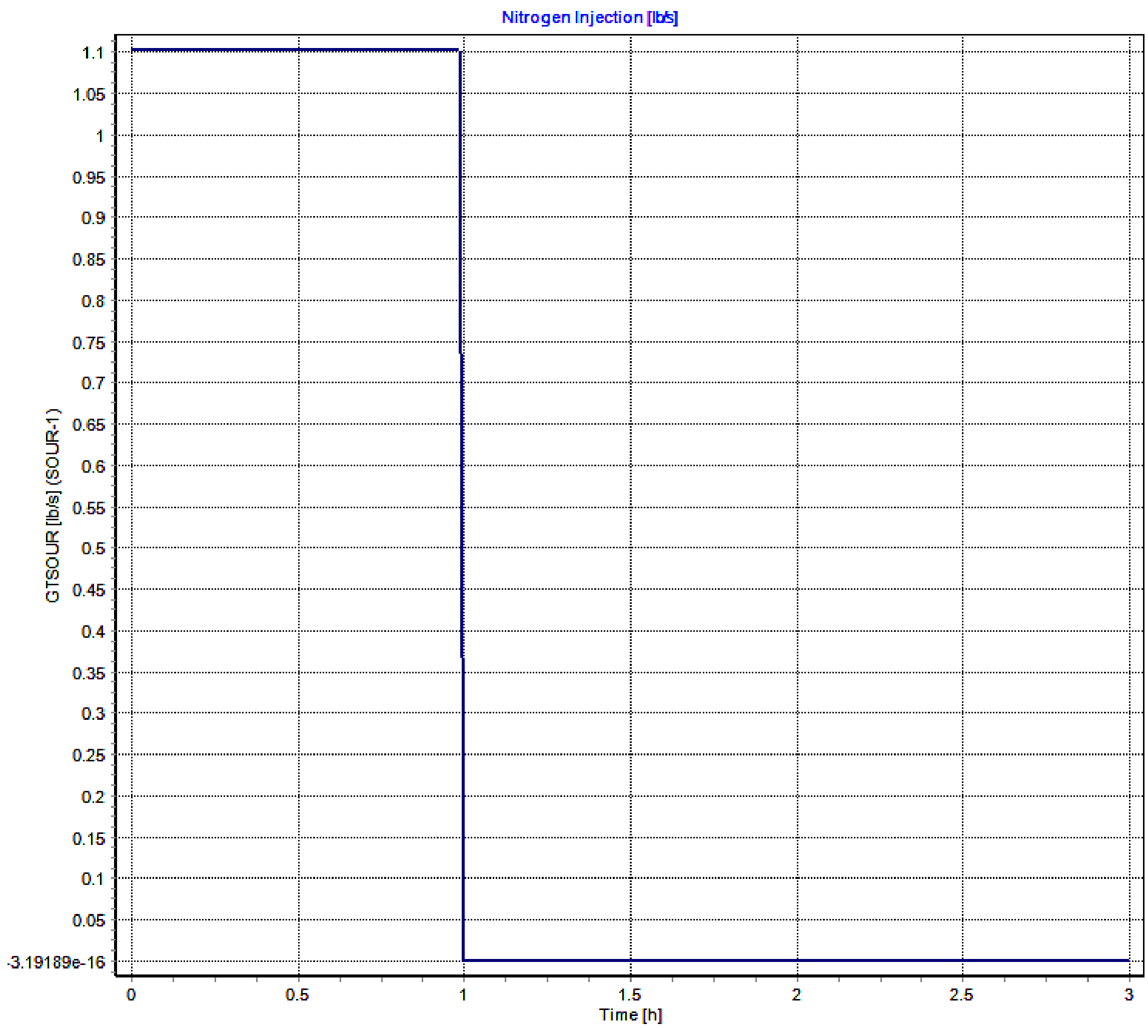


Figure 3.19. Nitrogen Injection Schedule

3.1.7.1. Reservoir contact. In OLGA, the reservoir information is set up in RESERVOIRCONTACT. For the Case Study, it is assumed that the reservoir produces with a NORMALIZED BACKPRESSURE IPR of 90MMcf/month with GAS as the main phase. This value can be calculated by reservoir modeling with history matching of the producing data from the Eagle Ford well 1A1.

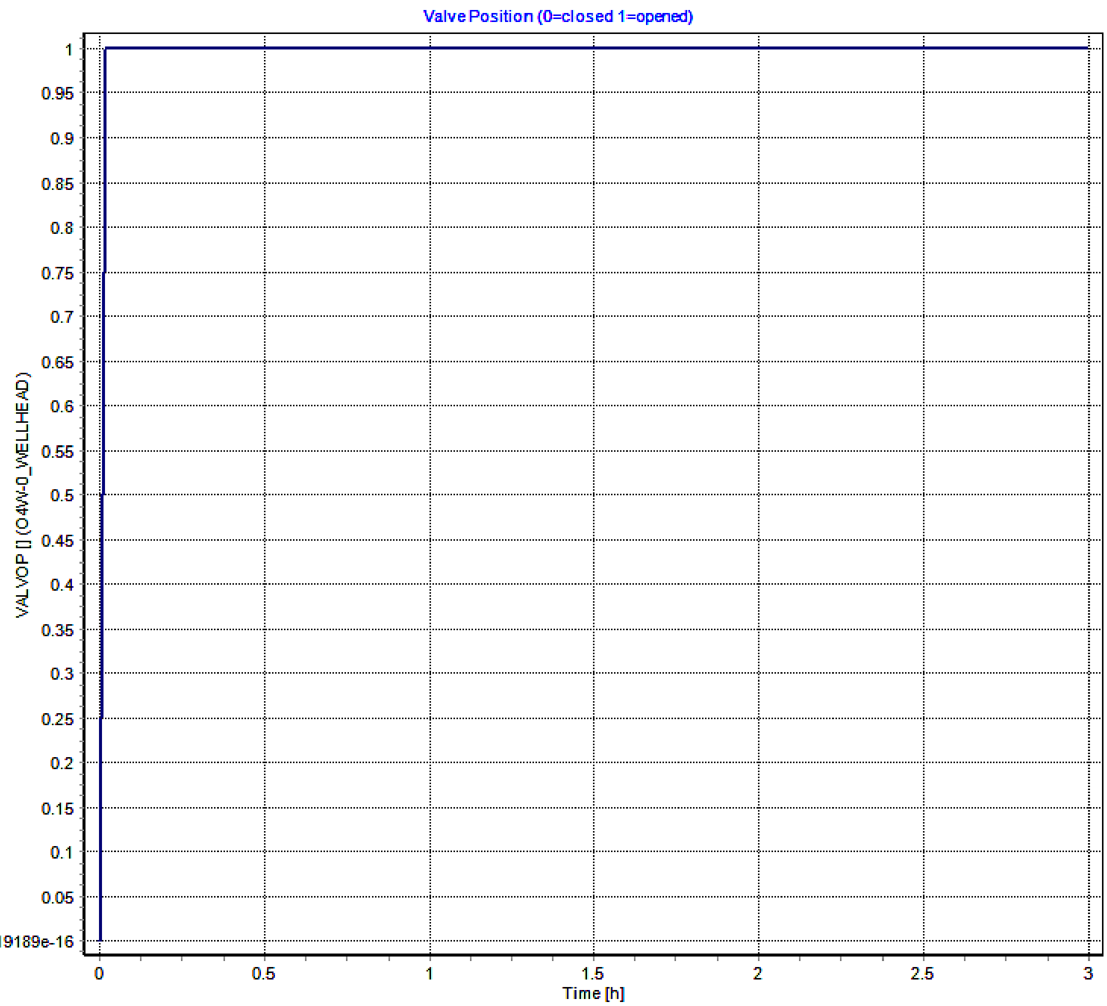


Figure 3.20. Valve Relative Position Schedule

3.1.7.2. Results. The following section show the results for the unloading simulation starting with the hold-up in the tubing, annulus and lateral section of the base case.

3.1.7.3. Hold-Up. Figure 3.21 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process starts.

Figure 3.22 shows the hold-up for the tubing, annulus and lateral section in a 3D model.

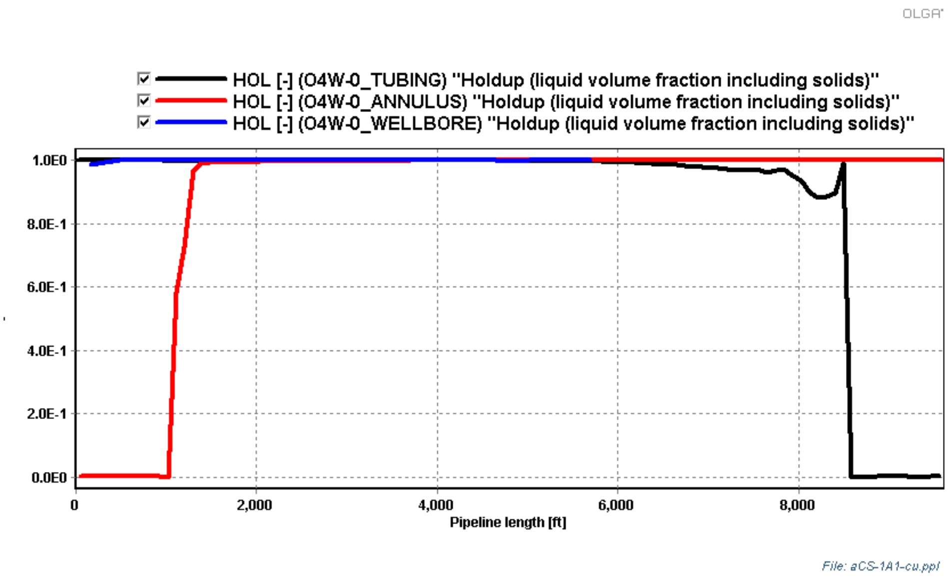


Figure 3.21. Hold-Up At Time=0min Of Unloading Process Profile Plot Case Study 1A1

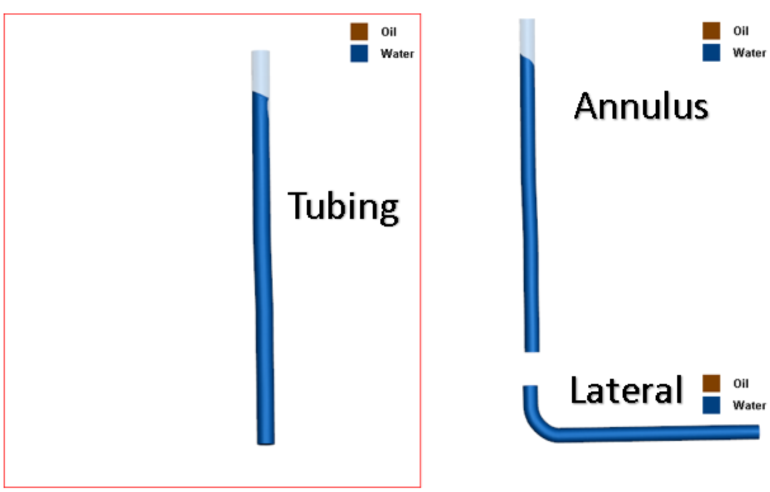


Figure 3.22. Hold-Up At Time=0min Of Unloading Process 3D Plot Case Study 1A1

Figure 3.23 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 10min.

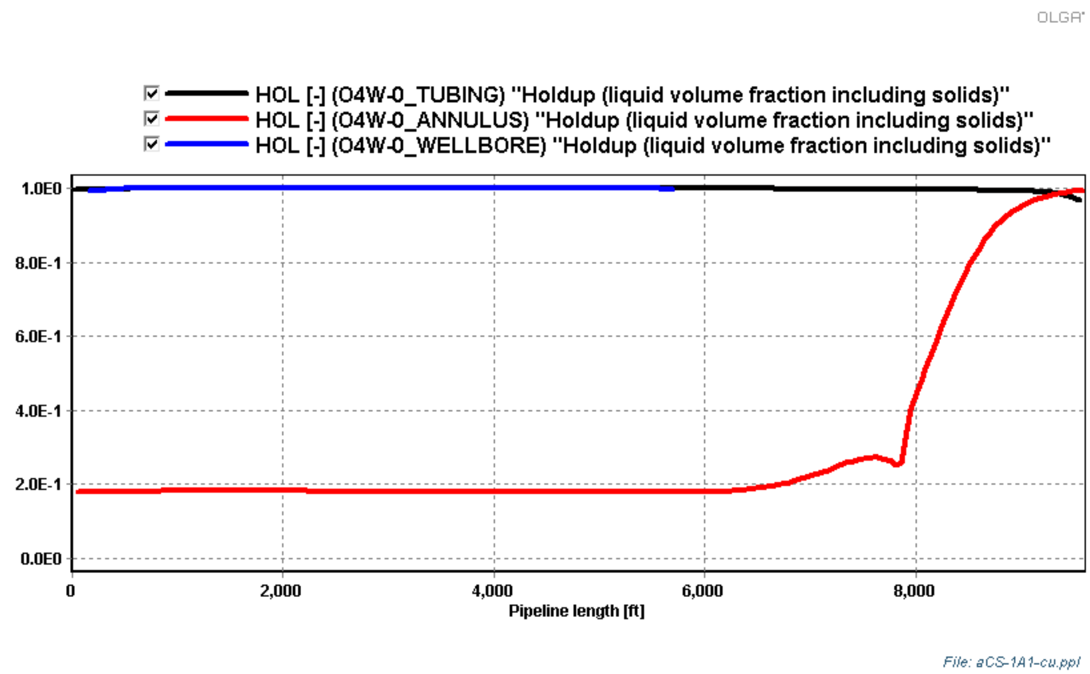


Figure 3.23. Hold-Up At Time=10min Of Unloading Process Profile Plot

Figure 3.24 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 10min of injection.

Figure 3.25 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 20min.

Figure 3.26 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 20min of injection.

Figure 3.27 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 30min.

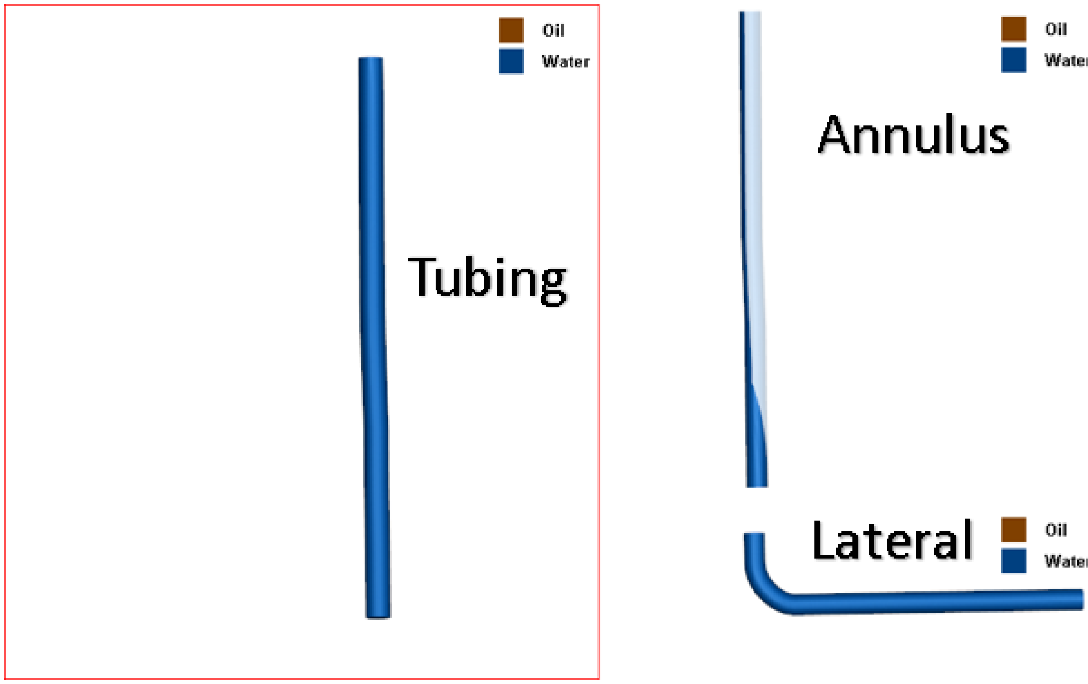


Figure 3.24. Hold-Up At Time=10min Of Unloading Process 3D Plot

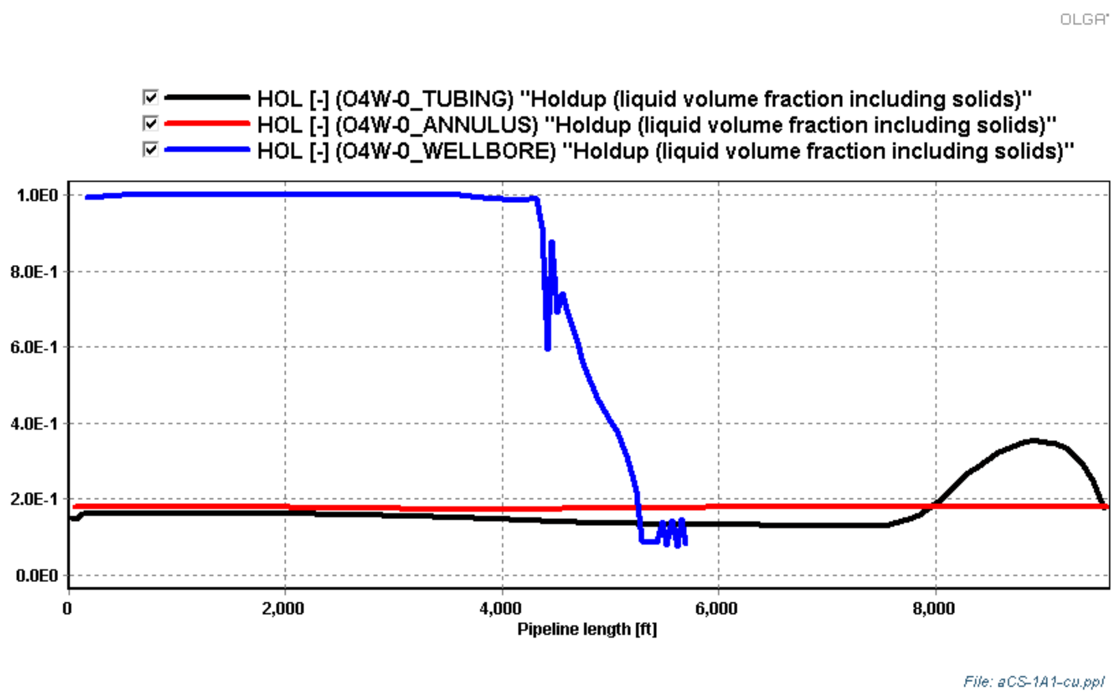


Figure 3.25. Hold-Up At Time=20min Of Unloading Process Profile Plot

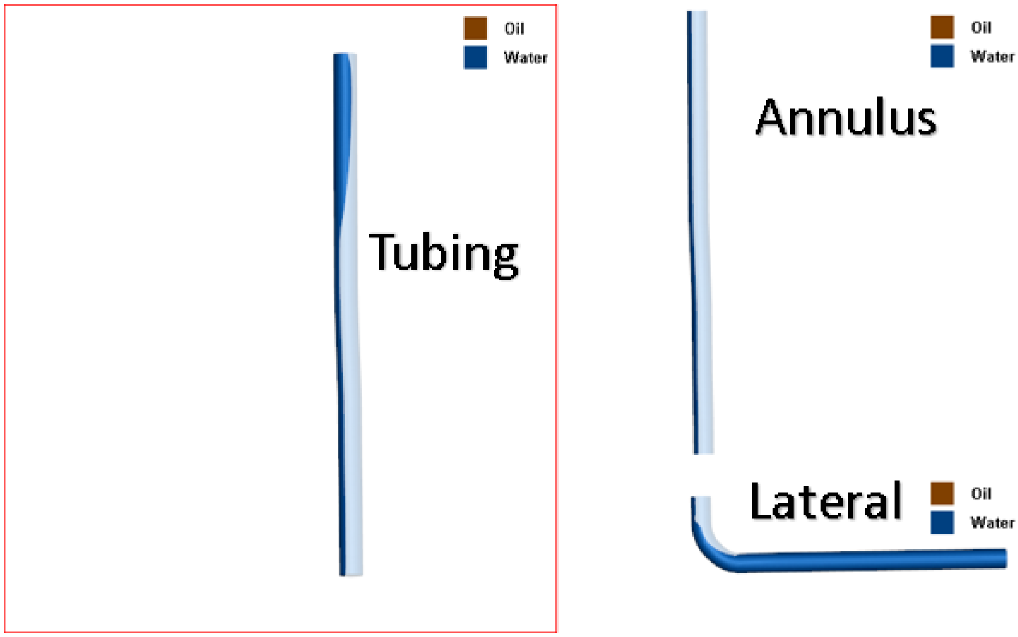


Figure 3.26. Hold-Up At Time=20min Of Unloading Process 3D Plot

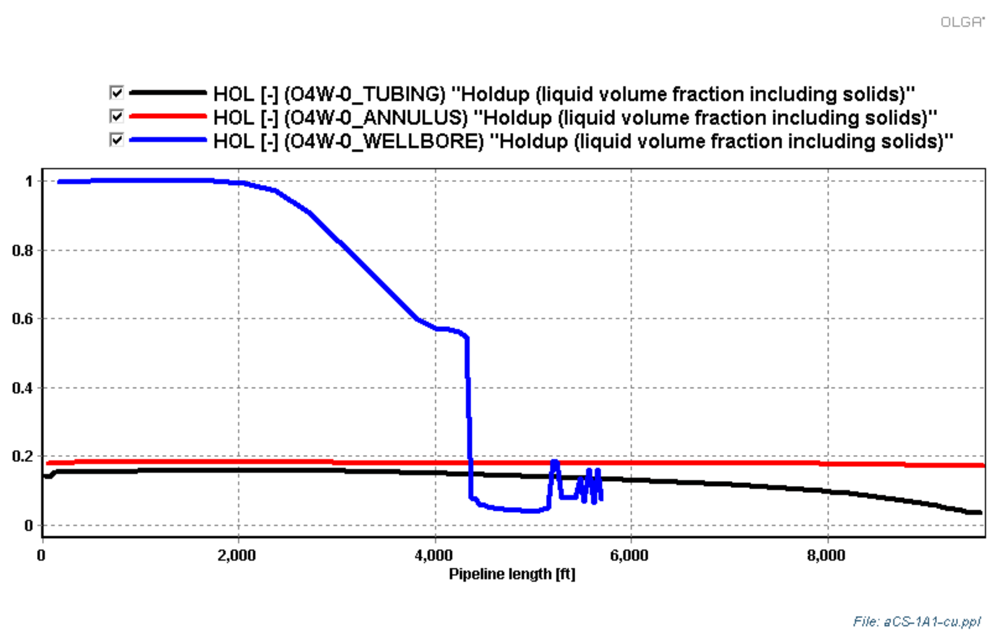


Figure 3.27. Hold-Up At Time=30min Of Unloading Process Profile Plot

Figure 3.28 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 30min of injection.

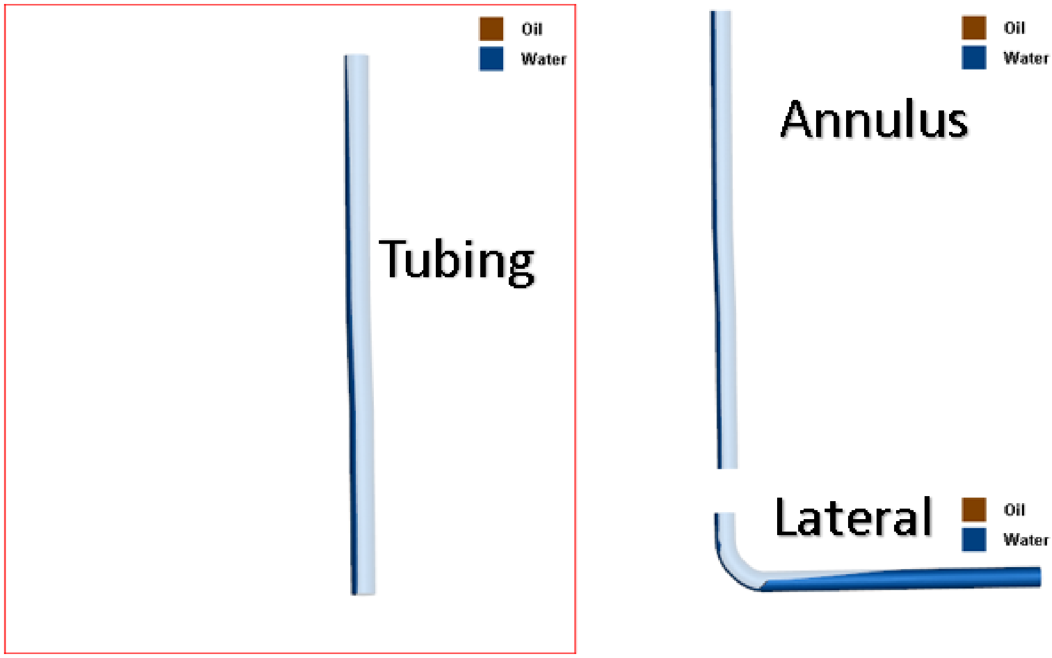


Figure 3.28. Hold-Up At Time=30min Of Unloading Process 3D Plot

Figure 3.29 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 40min.

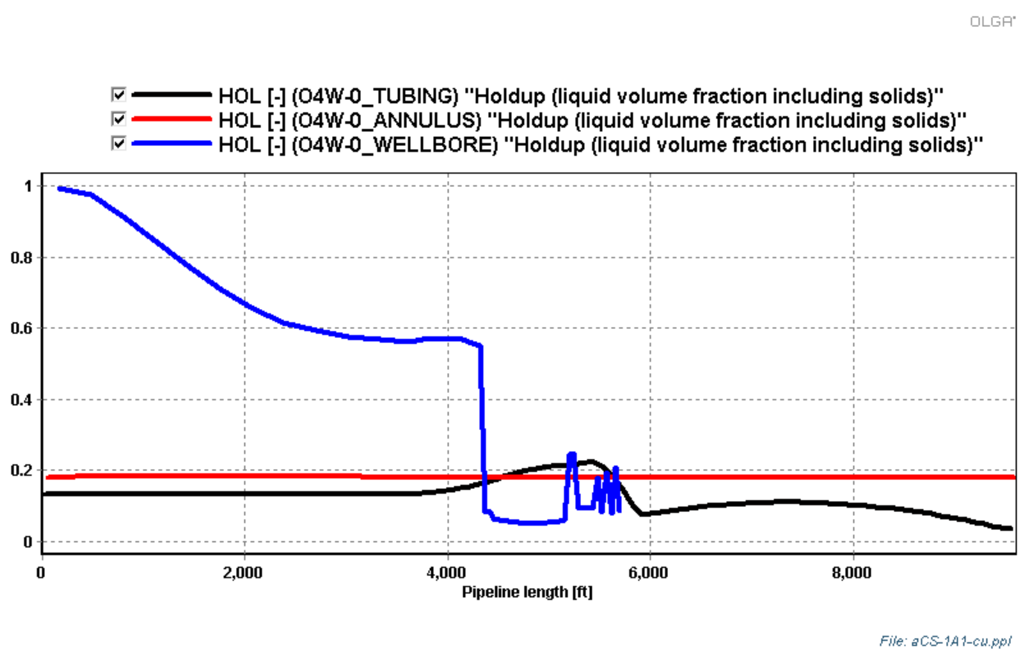


Figure 3.29. Hold-Up At Time=40min Of Unloading Process Profile Plot

Figure 3.30 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 40min of injection.

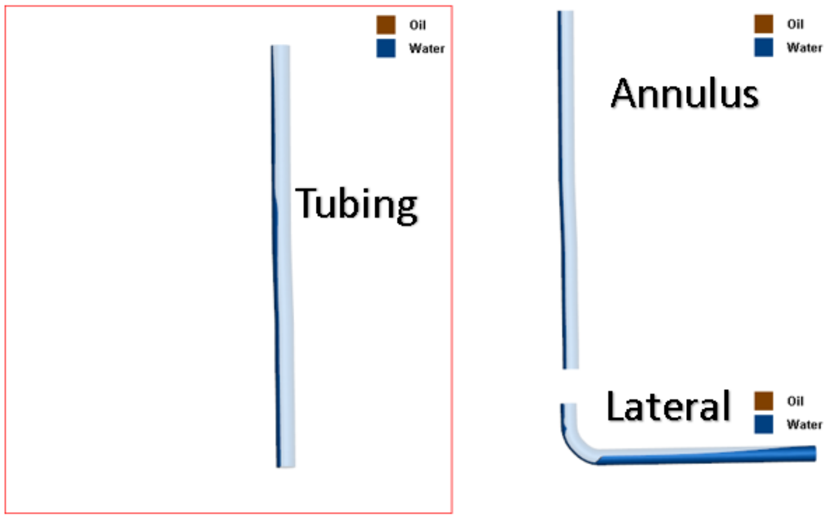


Figure 3.30. Hold-Up At Time=40min Of Unloading Process 3D Plot

Figure 3.31 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 50min.

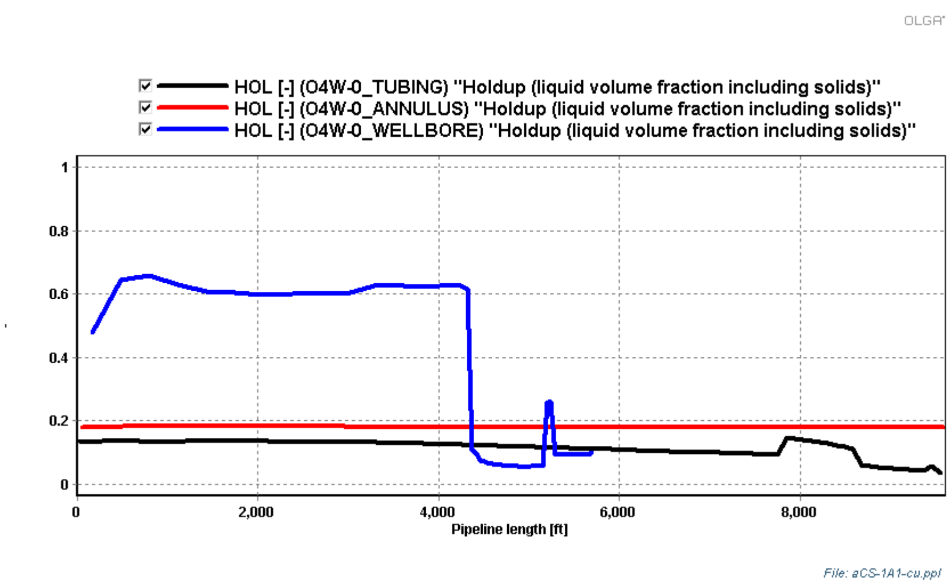


Figure 3.31. Hold-Up At Time=50min Of Unloading Process Profile Plot

Figure 3.32 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 50min of injection.

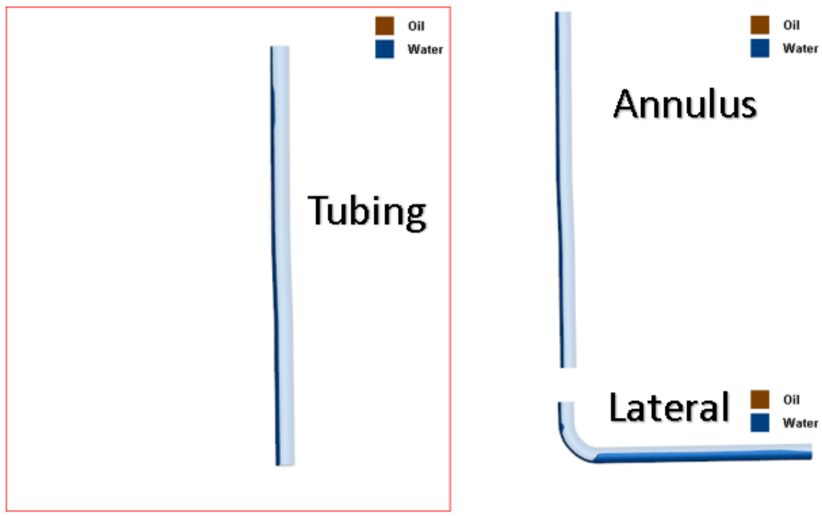


Figure 3.32. Hold-Up At Time=50min Of Unloading Process 3D Plot

Figure 3.33 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 60min.

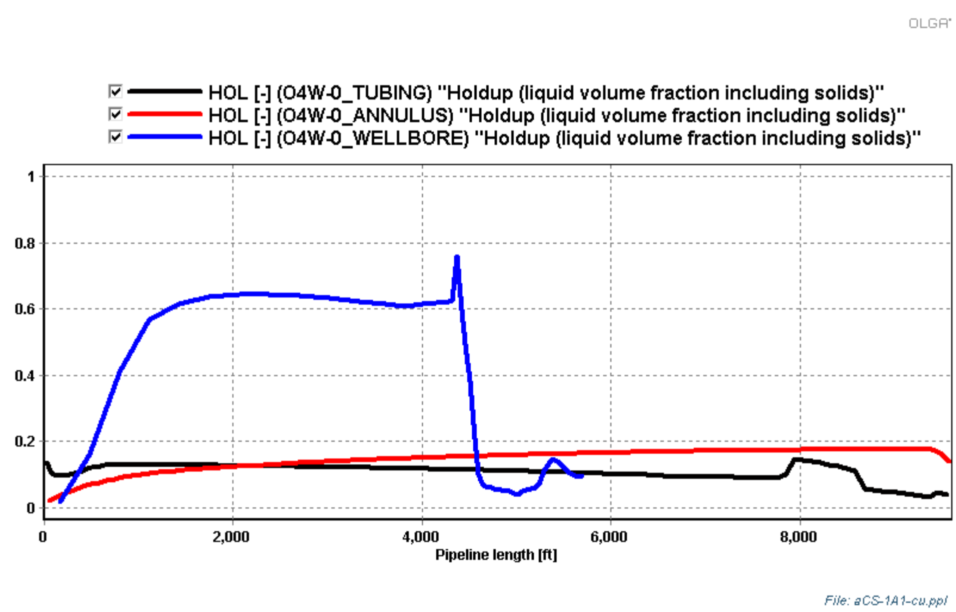


Figure 3.33. Hold-Up At Time=60min Of Unloading Process Profile Plot

Figure 3.34 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 60min of injection.

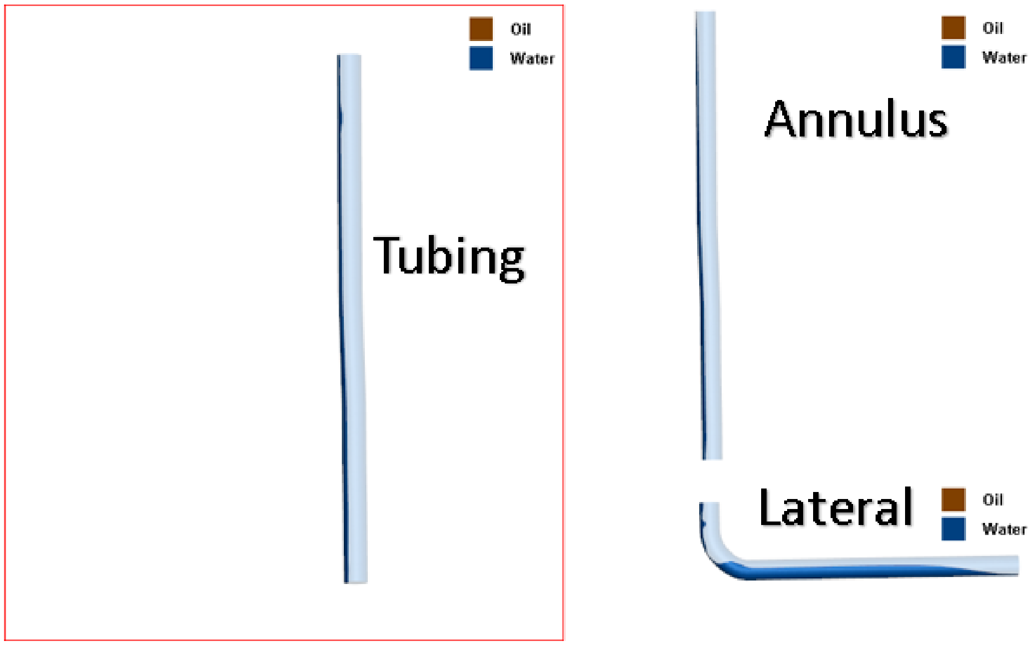


Figure 3.34. Hold-Up At Time=60min Of Unloading Process 3D Plot

As shown at this point, there is no column of liquid inside the annulus or the production tubing; therefore, the well is now unloaded. The injection of nitrogen is being shut down to allow the reservoir to flow naturally through the wellbore.

Figure 3.35 illustrates the hold-up 10min after nitrogen injection stops.

Figure 3.36 shows the 3D representation of the hold-up for the three sections of the wellbore.

As it is noticed, OLGA represents the GAS as Oil Label colored by brown color.

The gas starts to produce from the reservoir naturally, from the lateral section to the deviated section and going up through the vertical section.

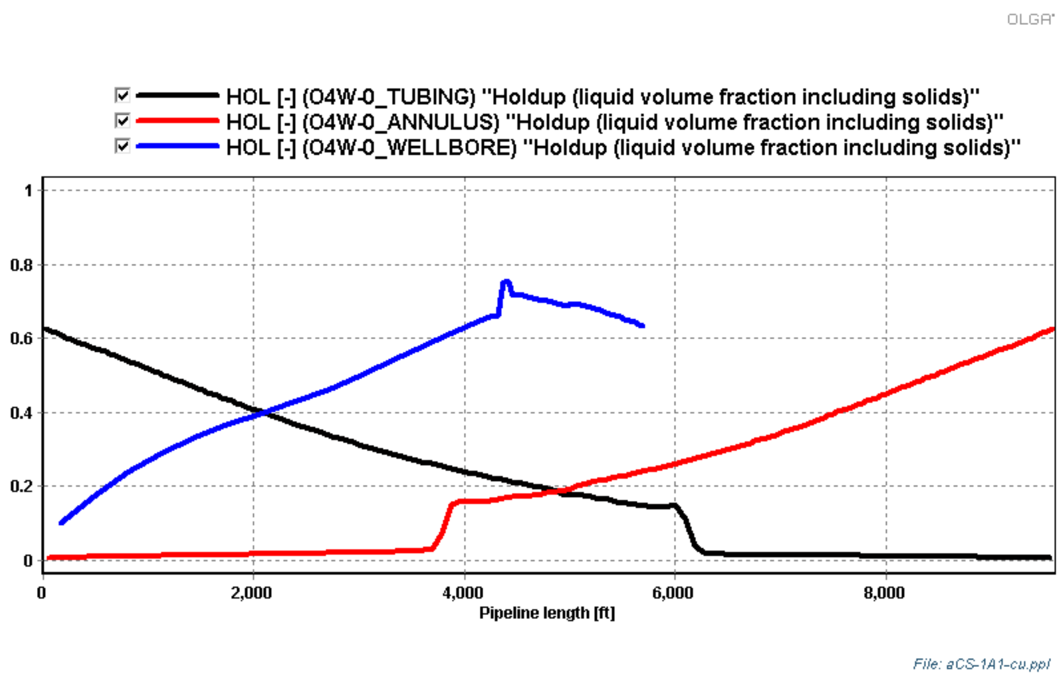


Figure 3.35. Hold-Up At Time=70min Of Unloading Process Profile Plot

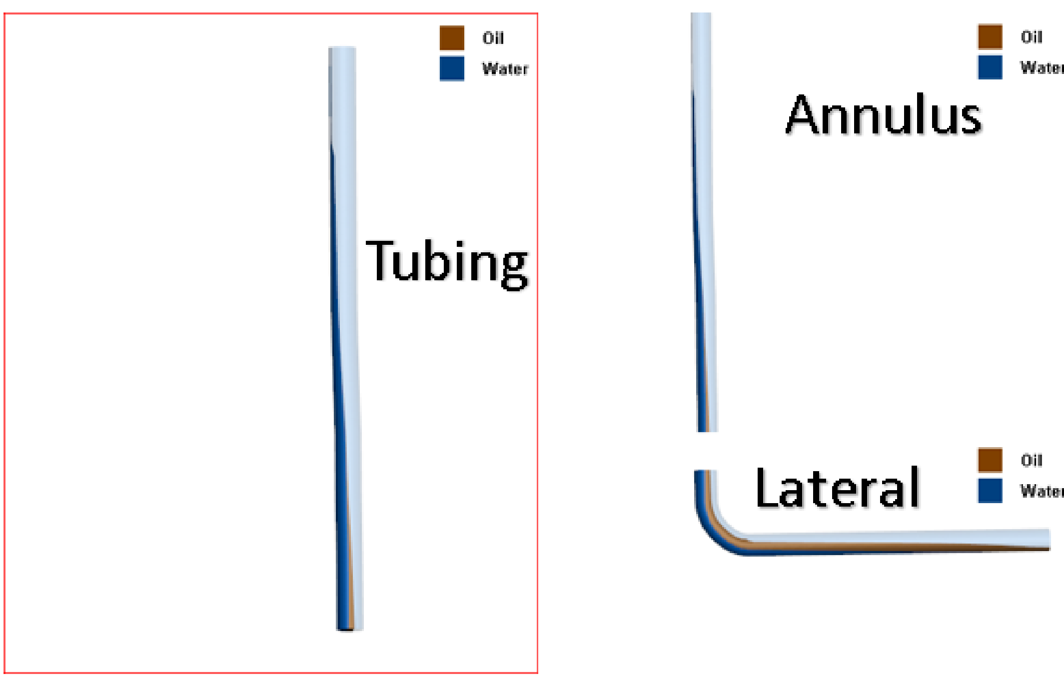


Figure 3.36. Hold-Up At Time=70min Of Unloading Process 3D Plot

The gas reaches the surface after 100min of the unloading process, which means that the gas well is in production 40min after the nitrogen stopped. This behavior is shown in Figure 3.37. The 3D illustration is presented in Figure 3.38.

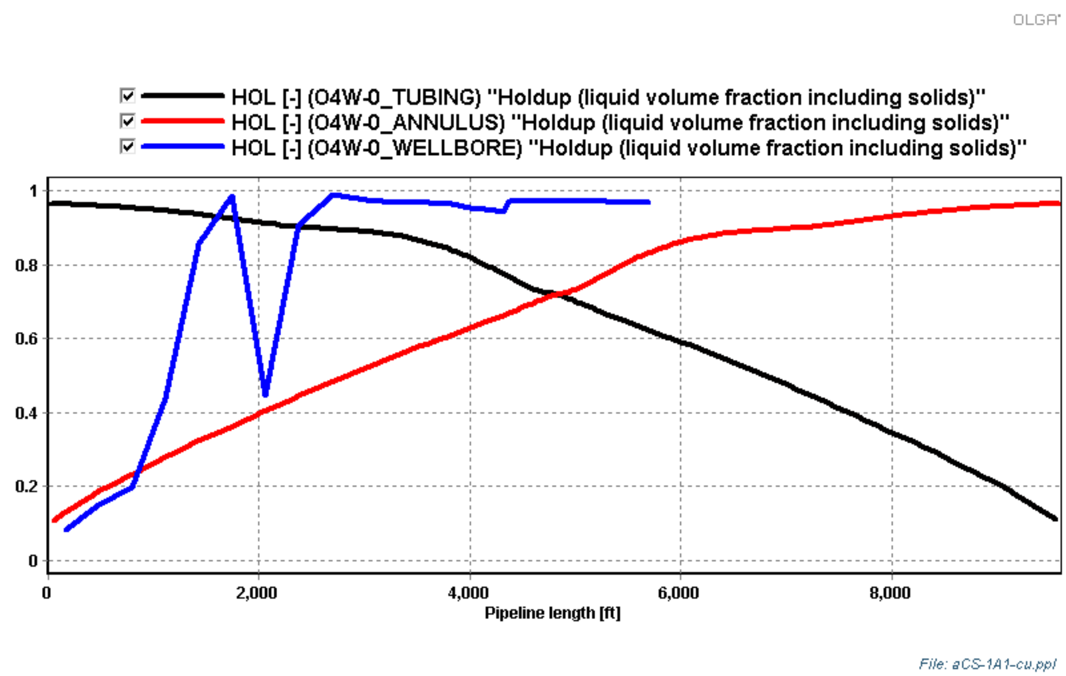


Figure 3.37. Hold-Up At Time=100min Of Unloading Process Profile Plot

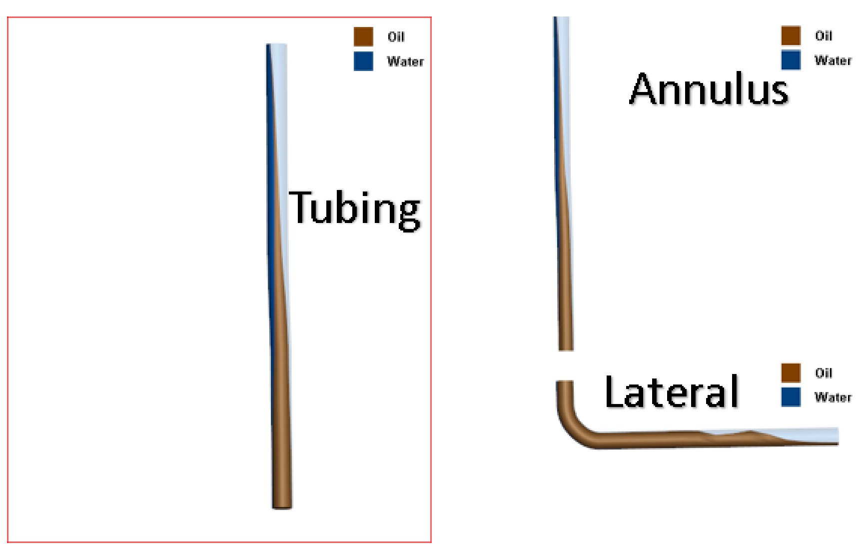


Figure 3.38. Hold-Up At Time=100min Of Unloading Process 3D Plot

3.1.7.4. Temperature and pressure. In this section, the temperature and pressure are plotted.

Figure 3.39 details the pressure and temperature at the tubing, annulus and lateral section of the wellbore when the unloading process starts. Figure 3.40 shows the same parameters after 30min of injection. Figure 3.41 and Figure 3.42 shows the profile plot at time 60min and 100min respectively.

3.2. PARAMETRIC STUDIES

This section describes several investigation of cases that vary from the base case.

These cases vary the well trajectory or inclination, the point at which the end-of-tubing (EOT) is set, nitrogen injection rate and pressure, and casing/tubing diameters.

The following section describes the behavior of nitrogen for unloading gas wells in with varying trajectory or inclination.

3.2.1. Case Study 2a2 (Vertical). This Case Study describes the behavior of the nitrogen for unloading in a vertical gas well.

3.2.1.1. Survey. Figure 3.43 describes a survey for vertical well trajectory.

3.2.1.2. Completion design. The completion design is the same as for the base case; the only difference is that the setting depth of the intermediate casing is located at 10550 ft, as shown in Figure 3.44.

The tubing remains the same as the Case Study 1A1. It reaches 9,606 ft from the surface.

3.2.1.3. Equipment. Similarly, to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

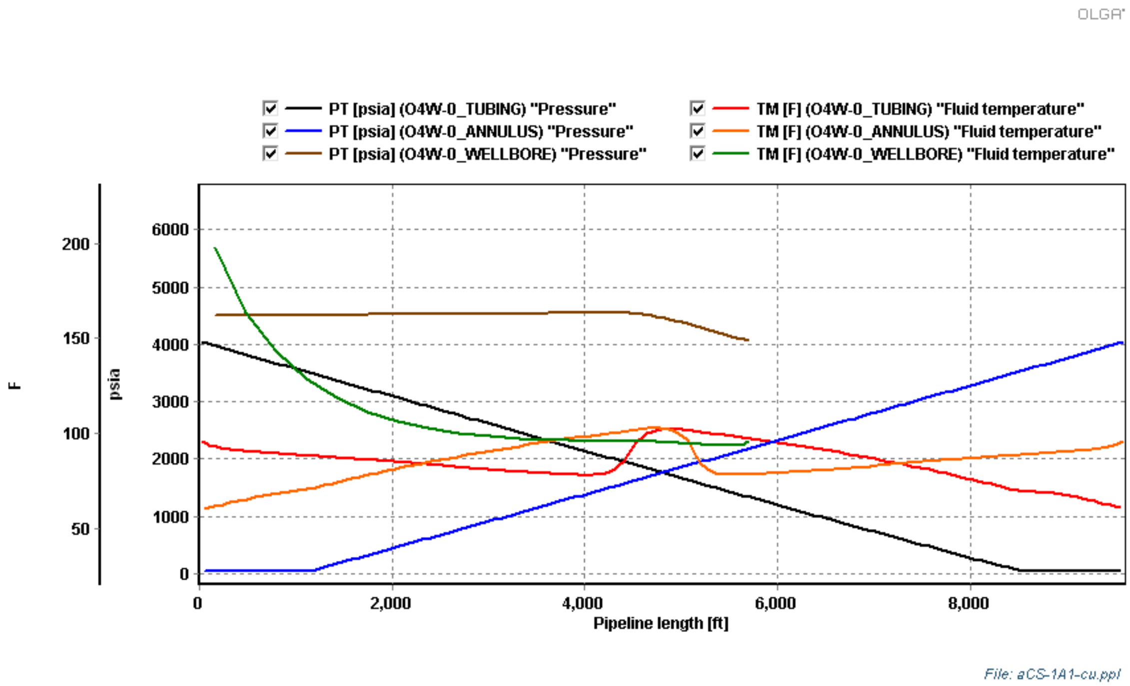


Figure 3.39. Temperature And Pressure At Time=0min Of Unloading Process Profile Plot

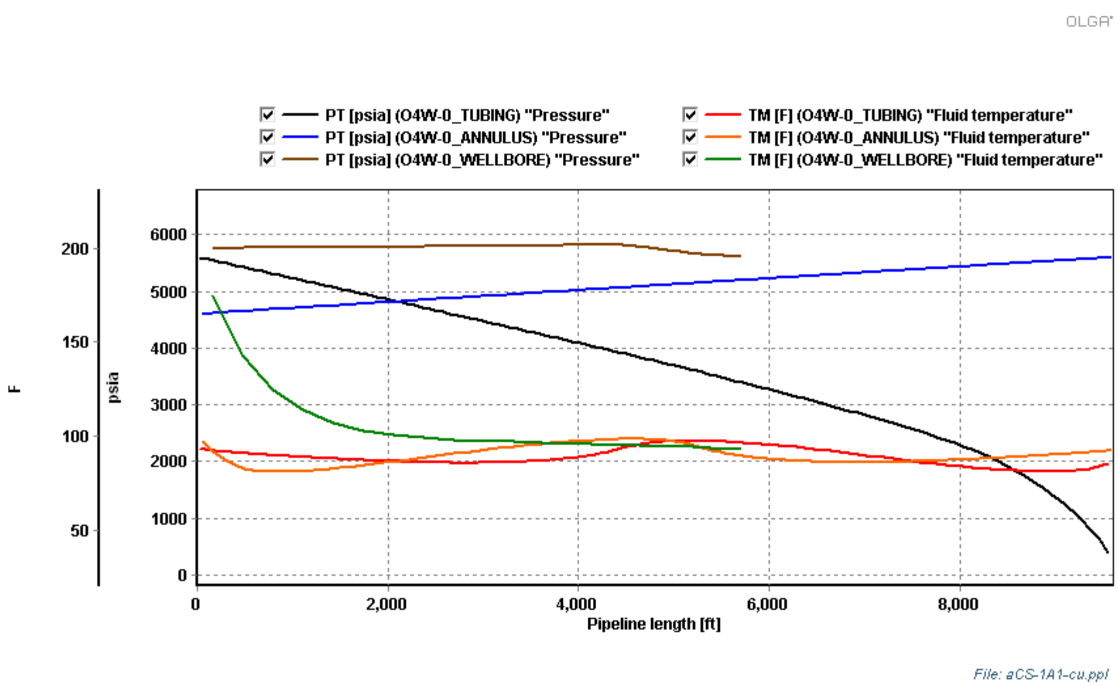


Figure 3.40. Temperature And Pressure At Time=30min Of Unloading Process Profile Plot

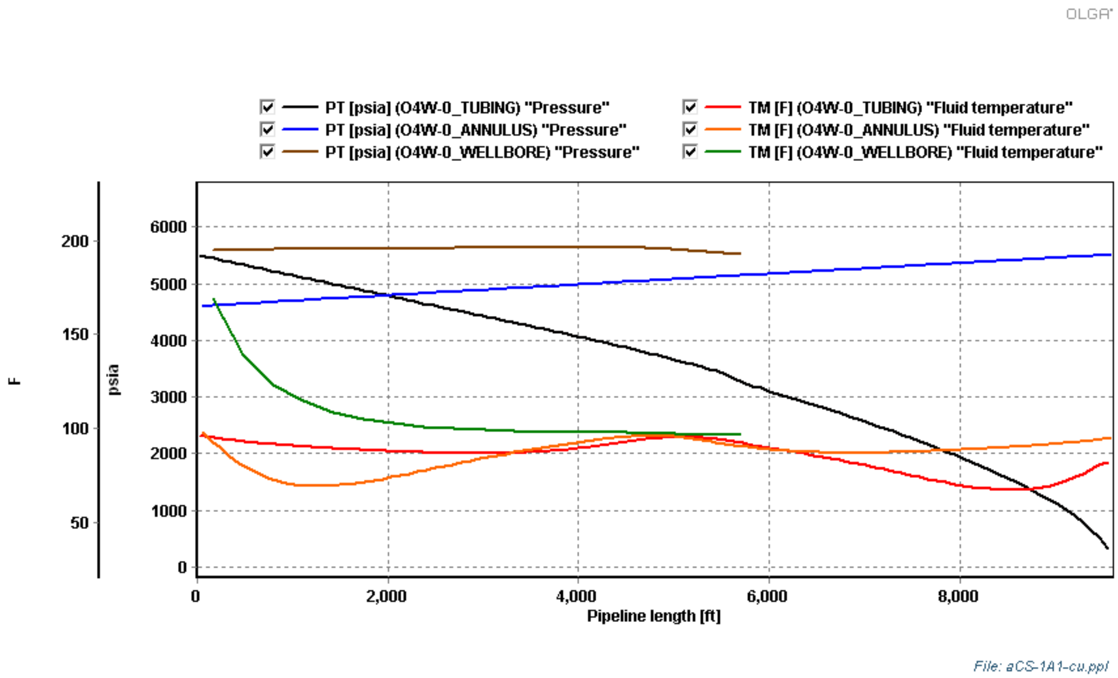


Figure 3.41. Temperature And Pressure At Time=60min Of Unloading Process Profile Plot

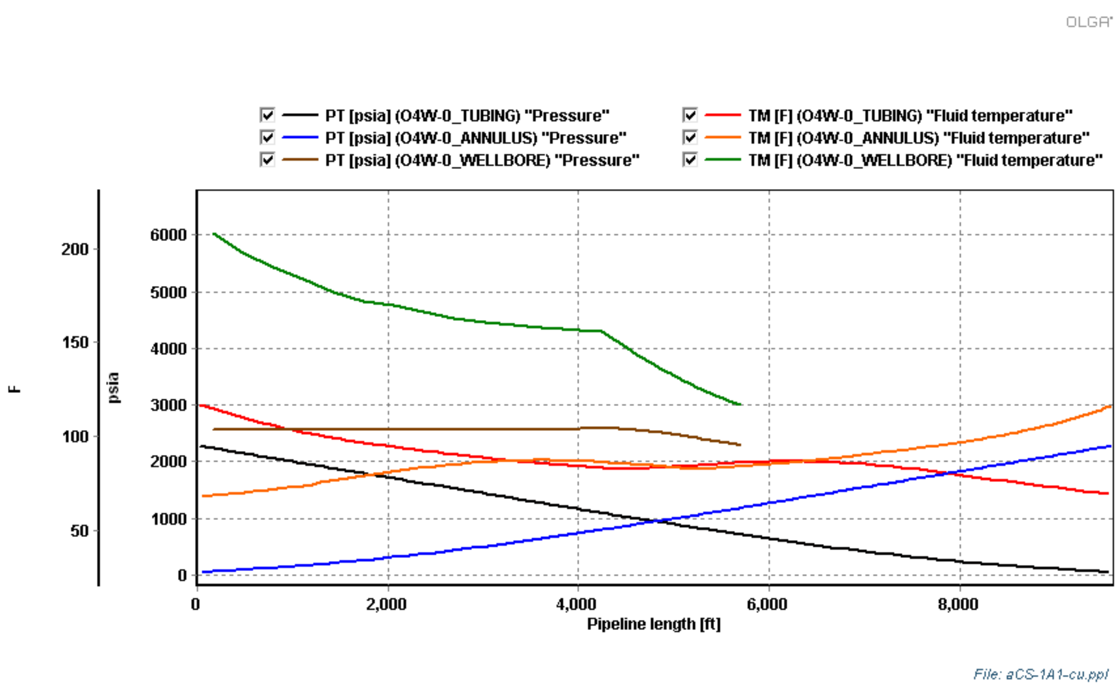


Figure 3.42. Temperature And Pressure At Time=100min Of Unloading Process Profile Plot

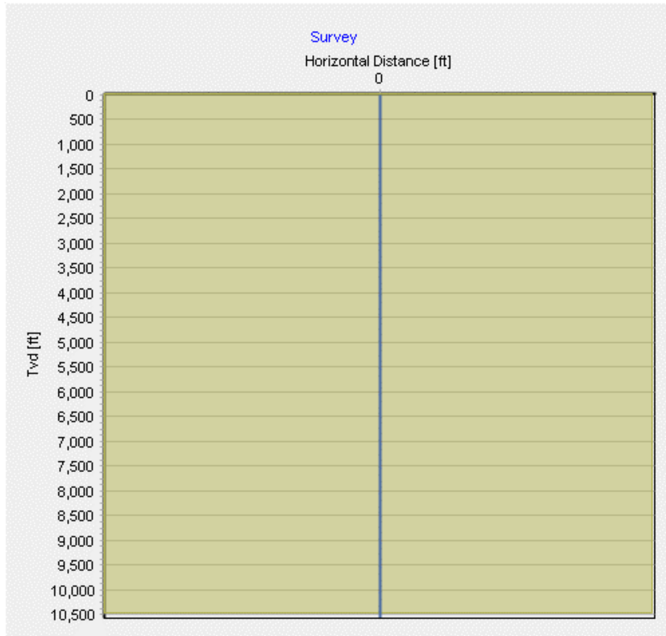


Figure 3.43. Case Study 2A2 Vertical Well Survey

This vertical well reaches the same pay zone as the Case Study 1A1.

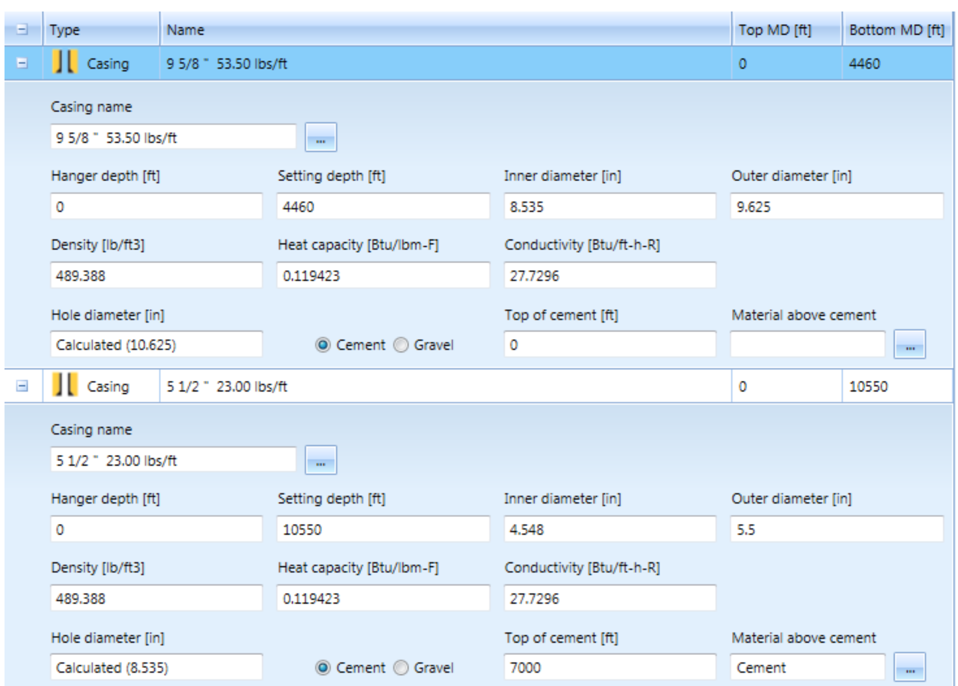


Figure 3.44. Case Study 2A2 Completion Design In Detail

3.2.1.4. Initial Conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.1.5. Unloading simulation conditions. It follows the same injection flow rate, temperature, pressure and time of injection which was applied to the Case Study 1A1.

3.2.1.6. Results. The following section will show the results for the unloading simulation starting with the hold-up in the tubing, annulus and lateral section of the Case Study 2A2.

3.2.1.7. Hold-Up. Figure 3.45 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process starts.

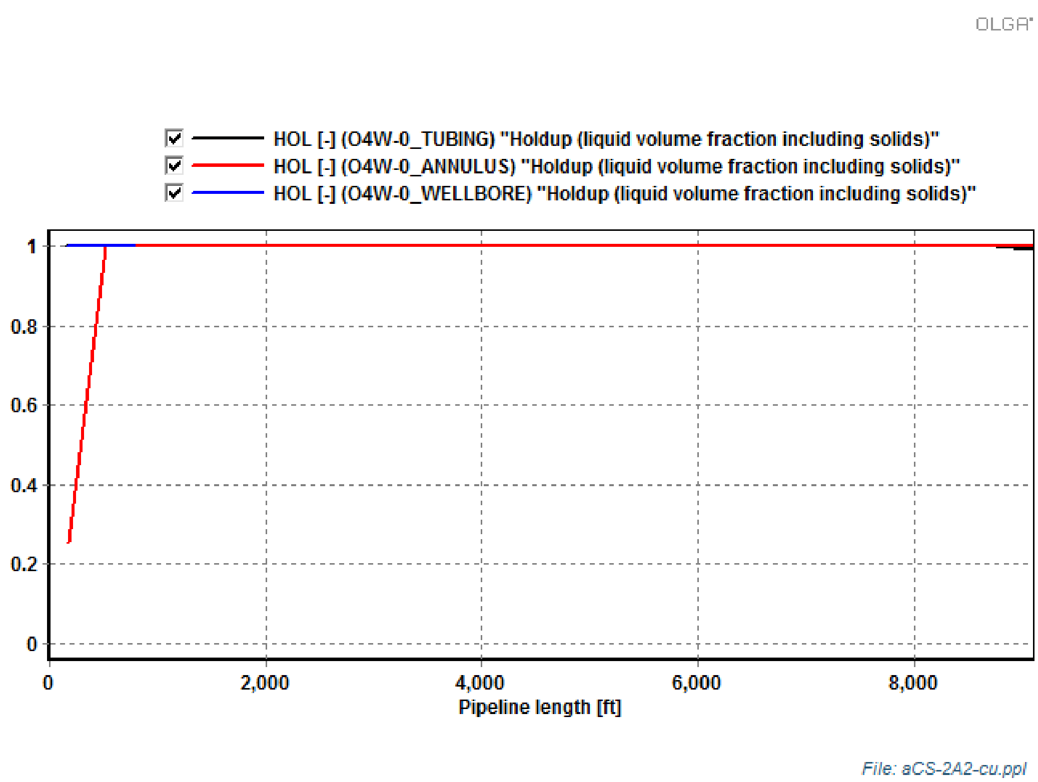


Figure 3.45. Hold-Up At Time=0min Of Unloading Process Profile Plot Case Study 2A2

Figure 3.46 shows the hold-up for the tubing, annulus and lateral section in a 3D model.

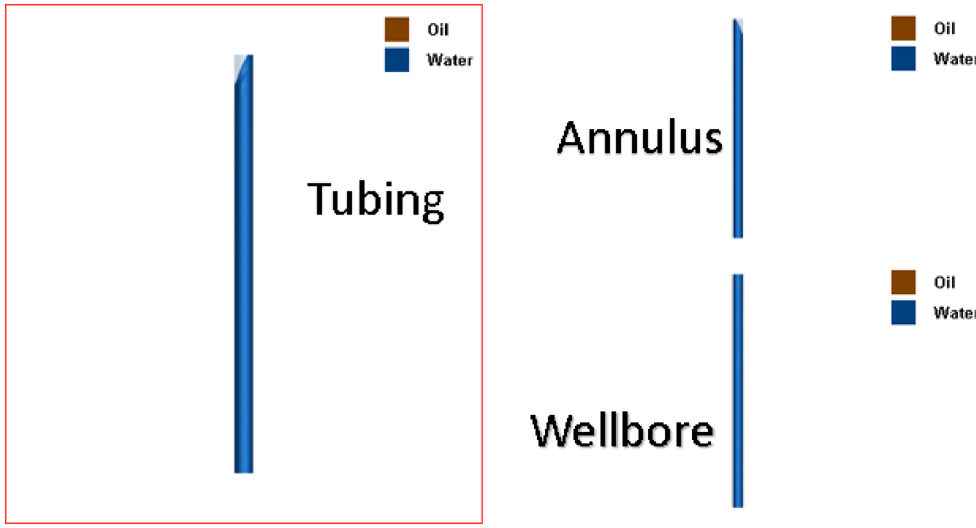


Figure 3.46. Hold-Up At Time=0min Of Unloading Process 3D Plot Case Study 2A2

Figure 3.47 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 10min.

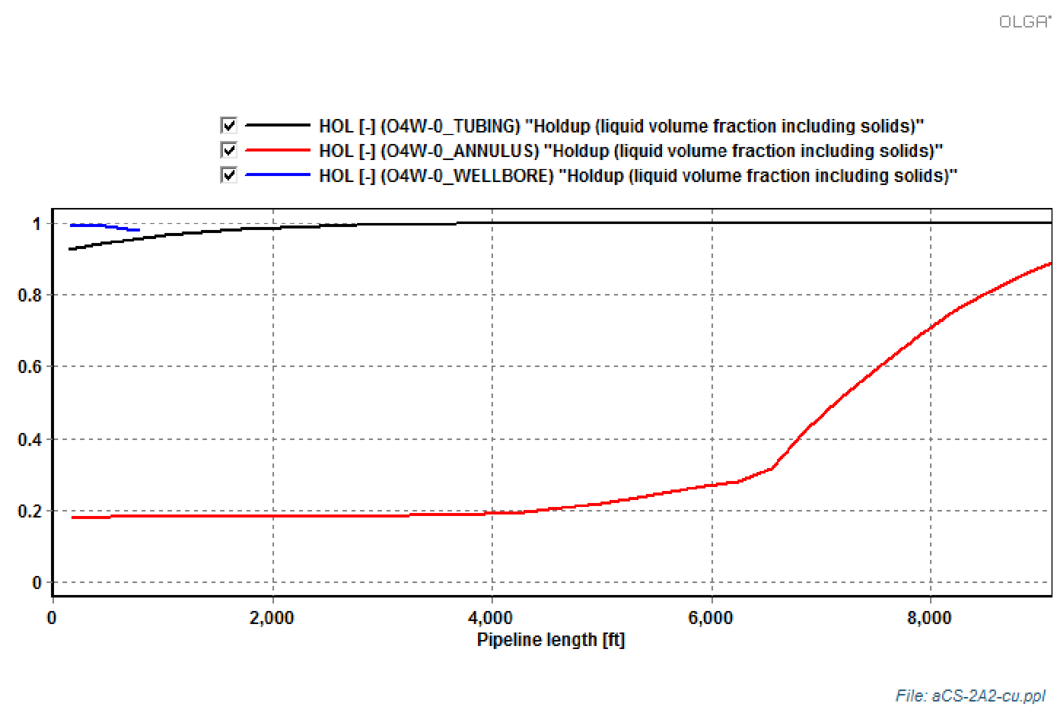


Figure 3.47. Hold-Up At Time=10min Of Unloading Process Profile Plot Case Study 2A2

Figure 3.48 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 10min of injection.

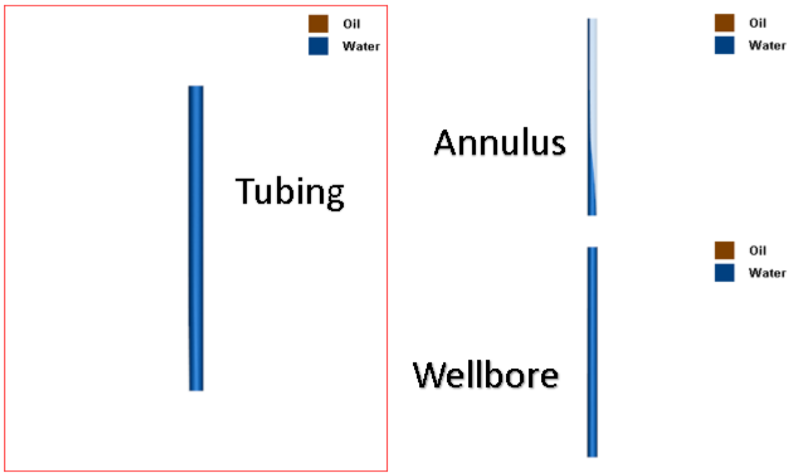


Figure 3.48. Hold-Up At Time=10min Of Unloading Process 3D Plot Case Study 2A2

Figure 3.49 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 20min.

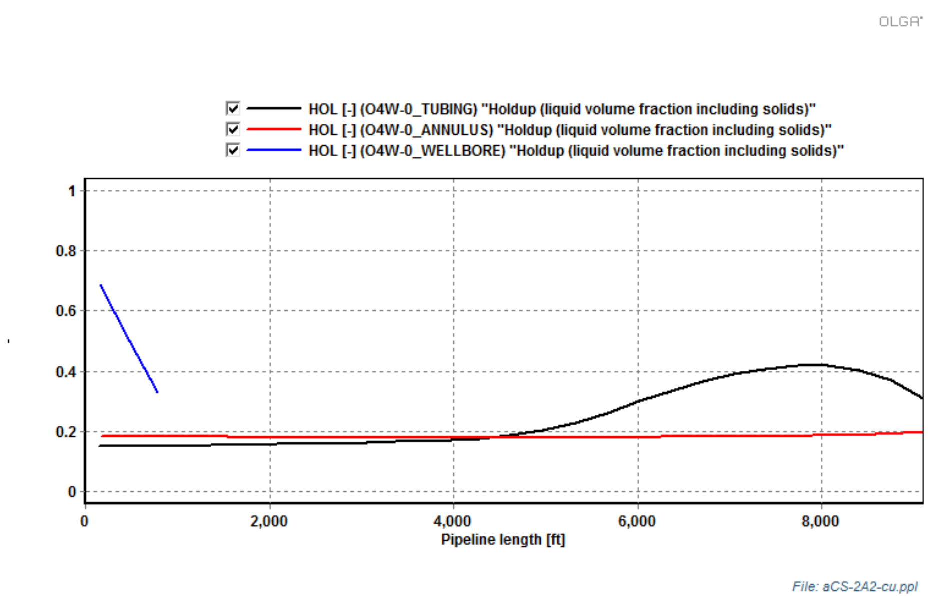


Figure 3.49. Hold-Up At Time=20min Of Unloading Process Profile Plot Case Study 2A2

Figure 3.50 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 20min of injection.

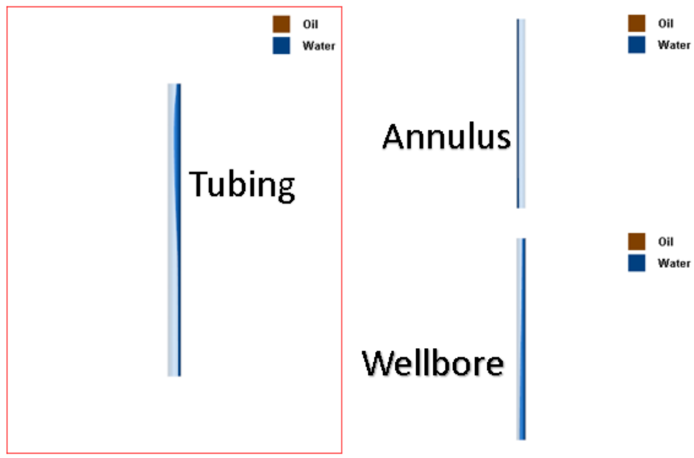


Figure 3.50. Hold-Up At Time=20min Of Unloading Process 3D Plot Case Study 2A2

Figure 3.51 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 30min.

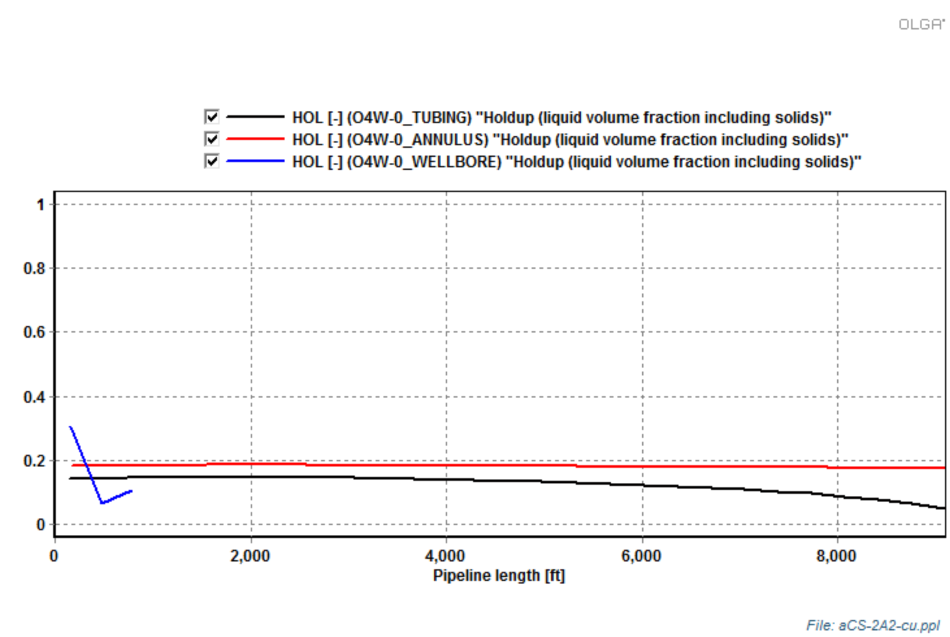


Figure 3.51. Hold-Up At Time=30min Of Unloading Process Profile Plot Case Study 2A2

Figure 3.52 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 30min of injection.

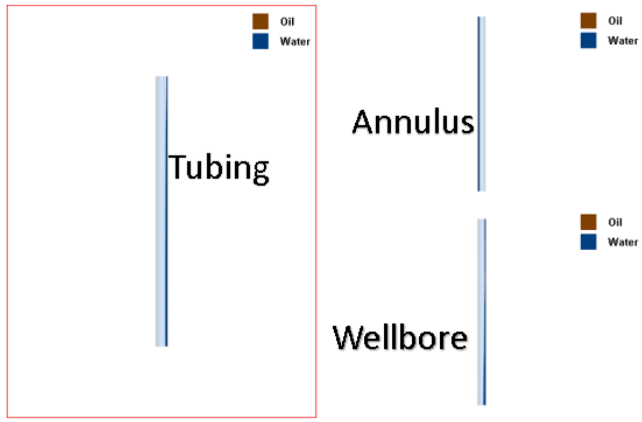


Figure 3.52. Hold-Up At Time=30min Of Unloading Process 3D Plot Case Study 2A2

At this point, the gas well is completely unloaded in less time than Case Study 1A1 since there is less fluid to remove because this well has not any lateral.

3.2.1.8. Temperature and pressure. In this section, the temperature and pressure are plotted for Case Study 2A2.

Figure 3.53 details the pressure and temperature at the tubing, annulus and lateral section of the wellbore when the unloading process starts. Figure 3.54 shows the same parameters after 20min of injection. Figure 3.55 shows the same parameters after 30min of injection.

3.2.2. Case Study 2a3 (30 Deg Deviation). This Case Study describes the behavior of the nitrogen for unloading in a 30 DEG deviated gas well.

3.2.2.1. Survey. Figure 3.56 describes a survey for a 30 DEG deviated well trajectory.

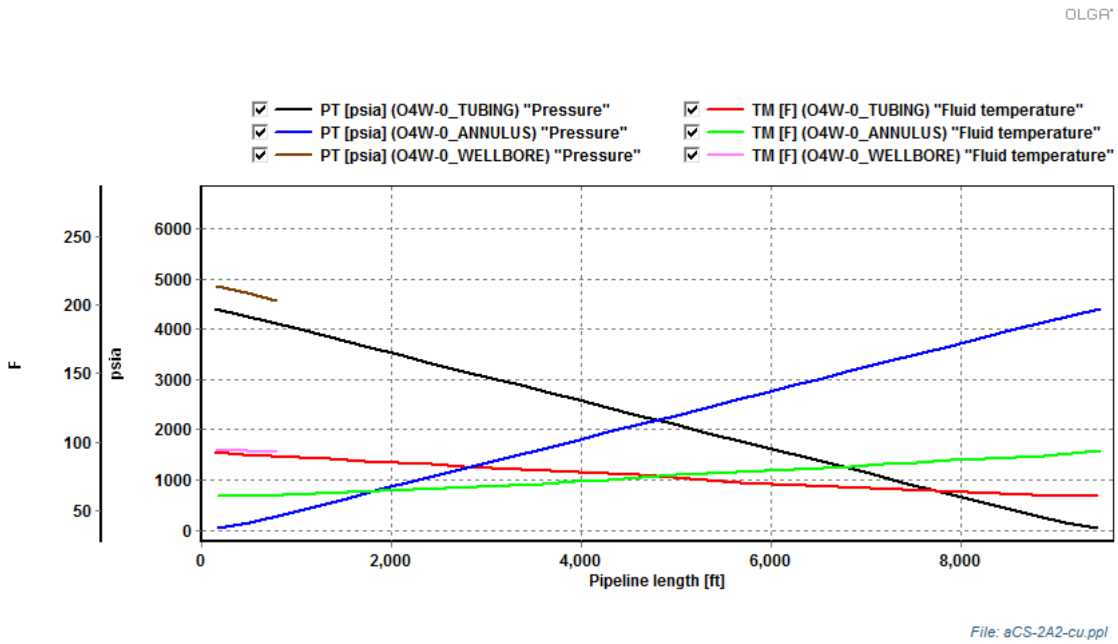


Figure 3.53. Temperature And Pressure At Time=0min Of Unloading Process Profile Plot Case Study 2A2

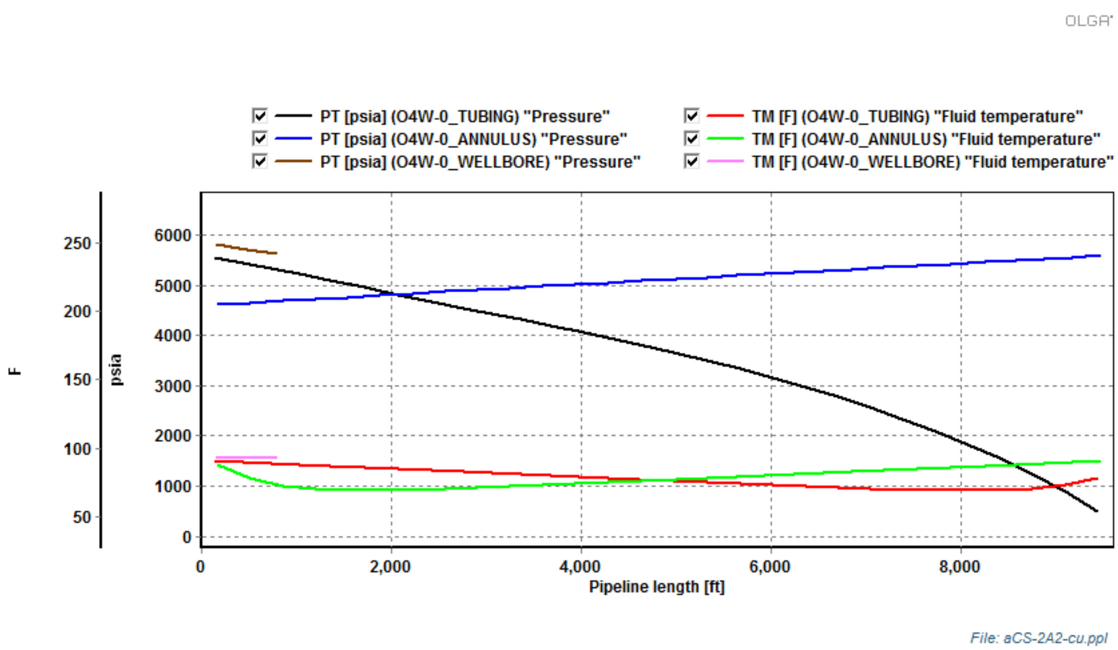


Figure 3.54. Temperature And Pressure At Time=20min Of Unloading Process Profile Plot Case Study 2A2

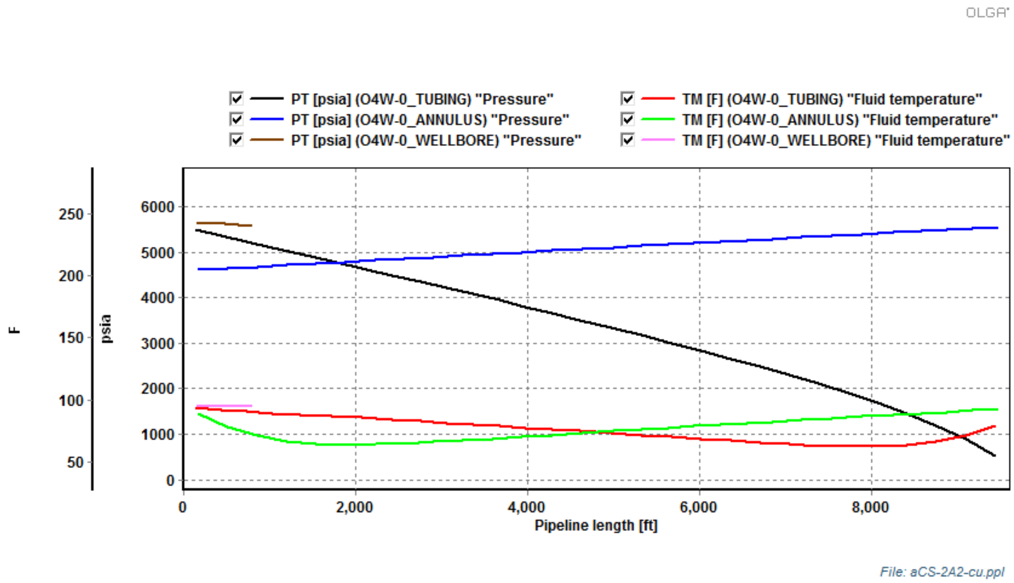


Figure 3.55. Temperature And Pressure At Time=30min Of Unloading Process Profile Plot Case Study 2A2

Figure 3.56. Case Study 2A3 30 DEG Deviated Well Survey

This 30 DEG deviated reaches the same pay zone as the Case Study 1A1.

3.2.2.2. Completion design. The completion design is the same as for the base case; the only difference is that the setting depth of the intermediate casing is located at 10550 ft, as shown in Figure 3.57.

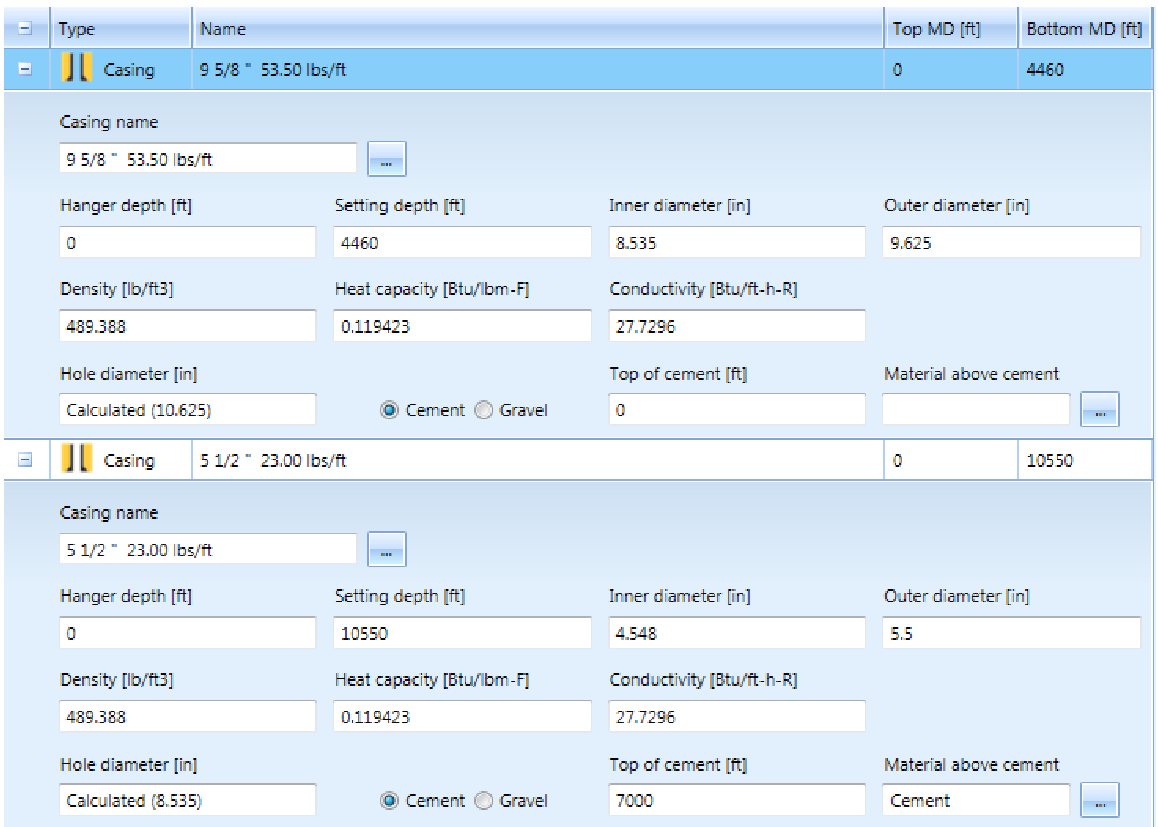


Figure 3.57. Case Study 2A3 Completion Design In Detail

The tubing remains the same as the Case Study 1A1. It reaches 9,606 ft from the surface.

3.2.2.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.2.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.2.5. Unloading simulation conditions. It follows the same injection flow rate, temperature, pressure and time of injection which was applied to the Case Study 1A1.

3.2.2.6. Results. The following section will show the results for the unloading simulation starting with the hold-up in the tubing, annulus and lateral section of the Case Study 2A3.

3.2.2.7. Hold-Up. Figure 3.58 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process starts.

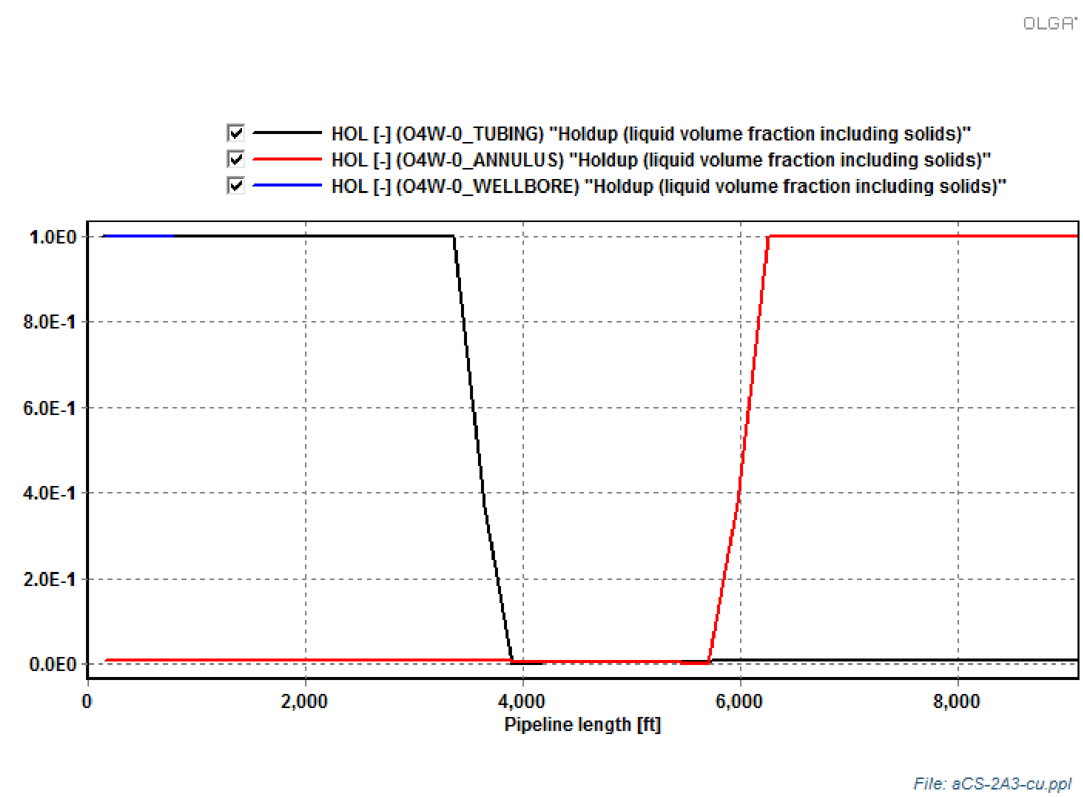


Figure 3.58. Hold-Up At Time=0min Of Unloading Process Profile Plot Case Study 2A3

Figure 3.59 shows the hold-up for the tubing, annulus and lateral section in a 3D model.

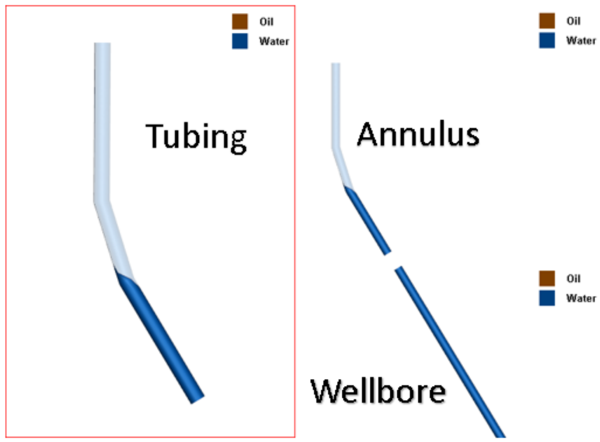


Figure 3.59. Hold-Up At Time=0min Of Unloading Process 3D Plot Case Study 2A3

Figure 3.60 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 10min.

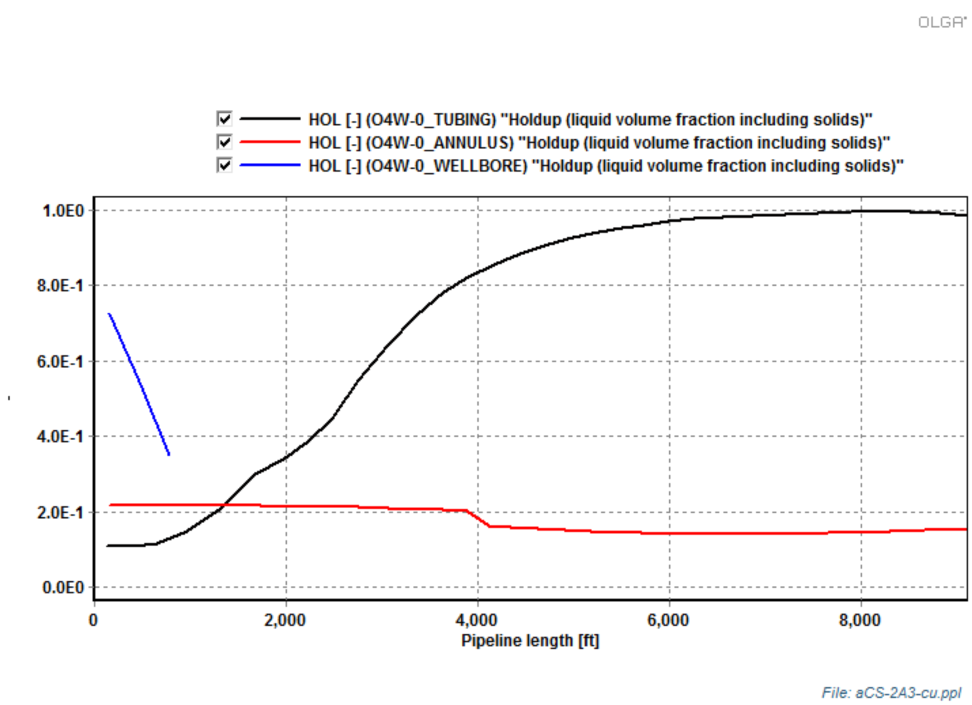


Figure 3.60. Hold-Up At Time=10min Of Unloading Process Profile Plot Case Study 2A3

Figure 3.61 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 10min of injection.

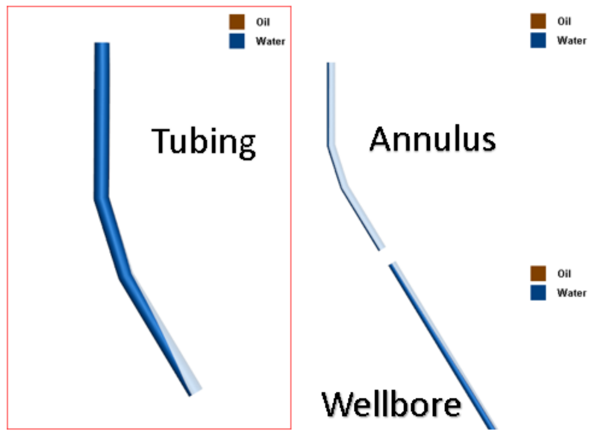


Figure 3.61. Hold-Up At Time=10min Of Unloading Process 3D Plot Case Study 2A3

Figure 3.62 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 20min.

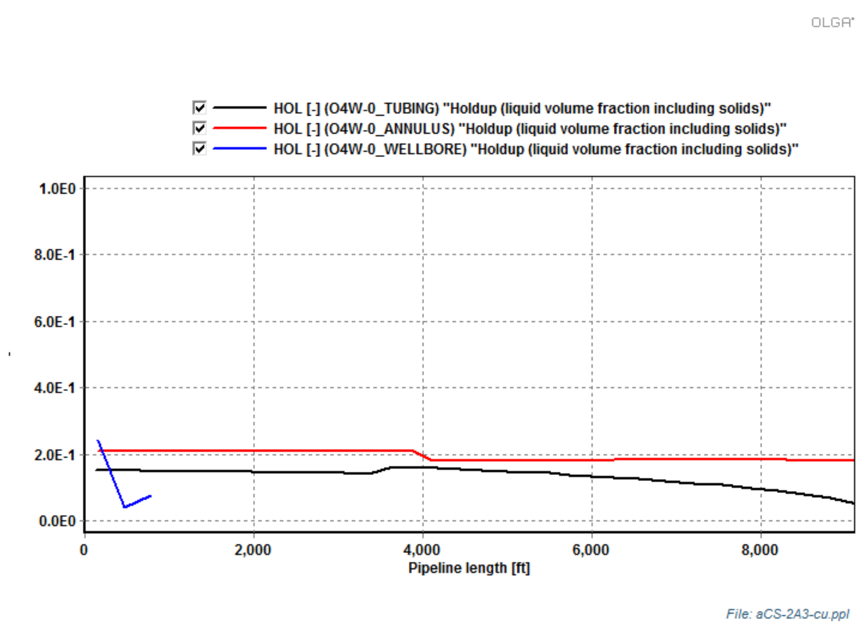


Figure 3.62. Hold-Up At Time=20min Of Unloading Process Profile Plot Case Study 2A3

Figure 3.63 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 20min of injection.

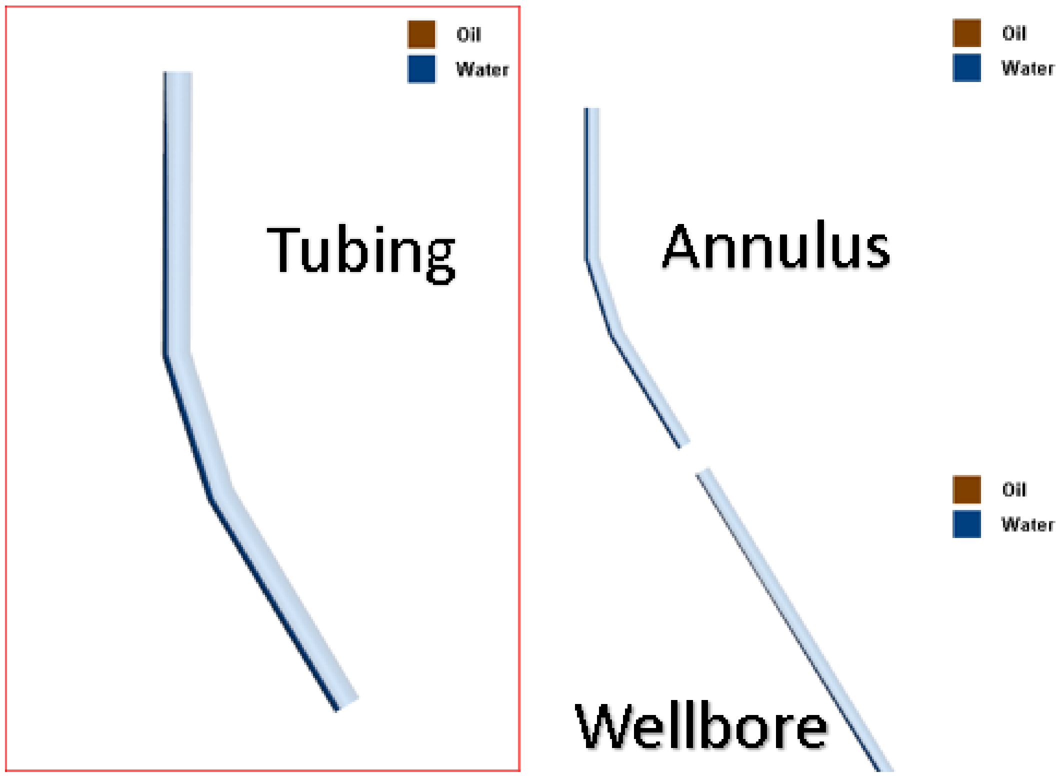


Figure 3.63. Hold-Up At Time=20min Of Unloading Process 3D Plot Case Study 2A3

Within the first 20 minutes, the well is completely unloaded.

3.2.2.8. Temperature and pressure. In this section, the temperature and pressure are plotted for Case Study 2A3.

Figure 3.64 details the pressure and temperature at the tubing, annulus and lateral section of the wellbore when the unloading process starts.

Figure 3.65 shows the same parameters after 10min of injection. Figure 3.66 shows the same parameters after 20min of injection.

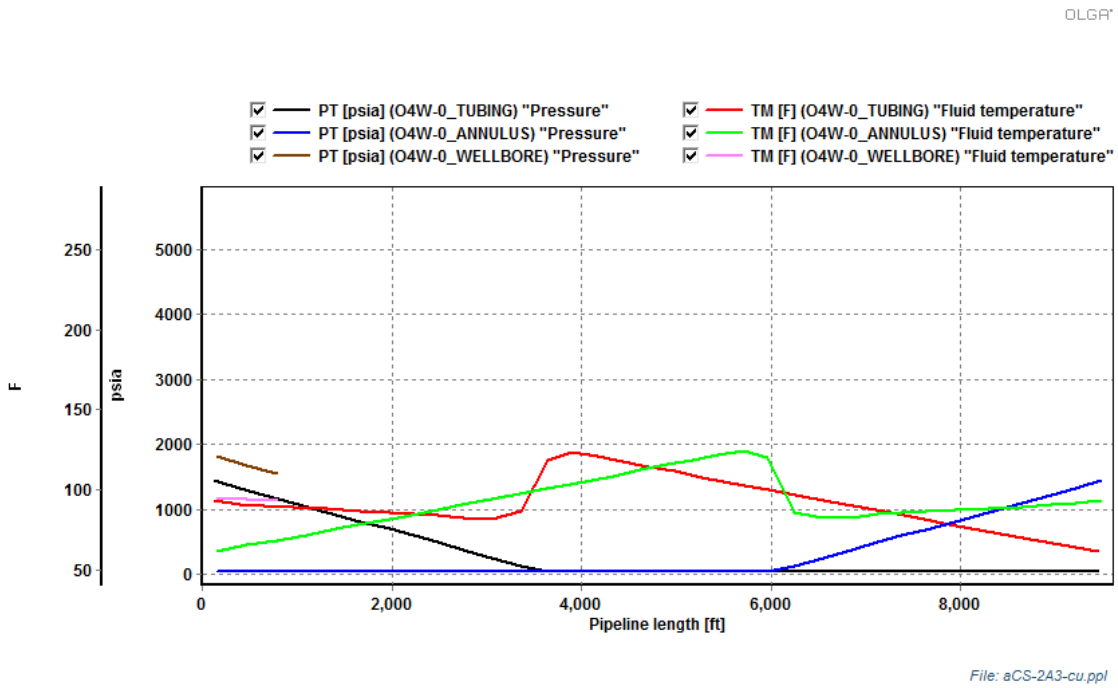


Figure 3.64. Temperature And Pressure At Time=0min Of Unloading Process Profile Plot Case Study 2A3

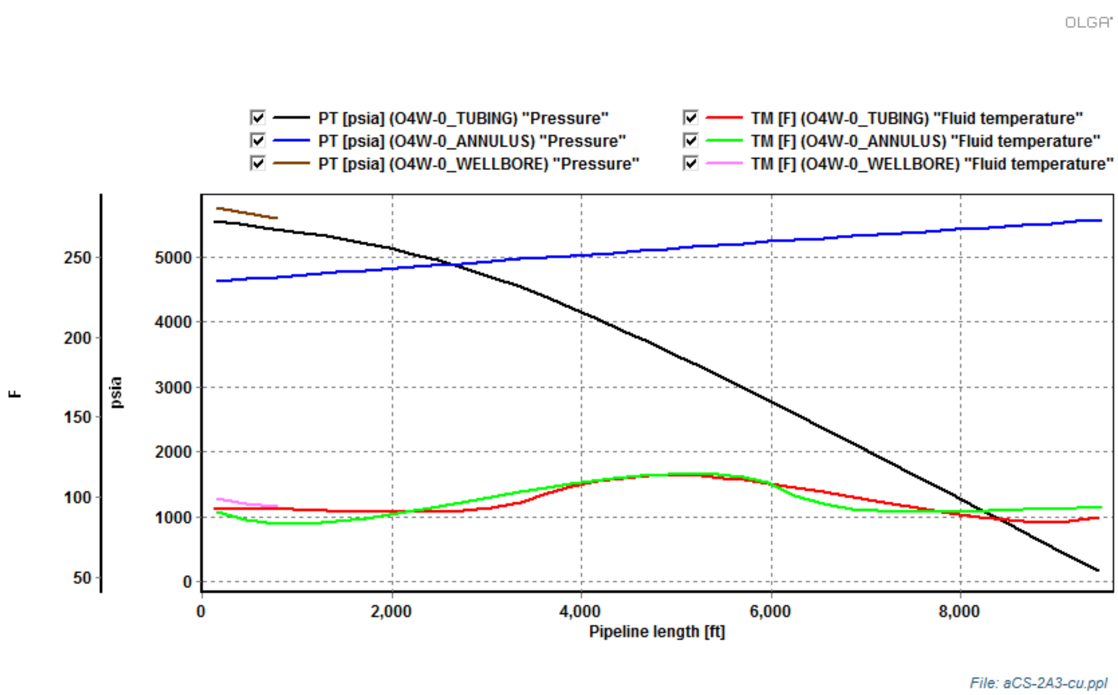


Figure 3.65. Temperature And Pressure At Time=10min Of Unloading Process Profile Plot Case Study 2A3

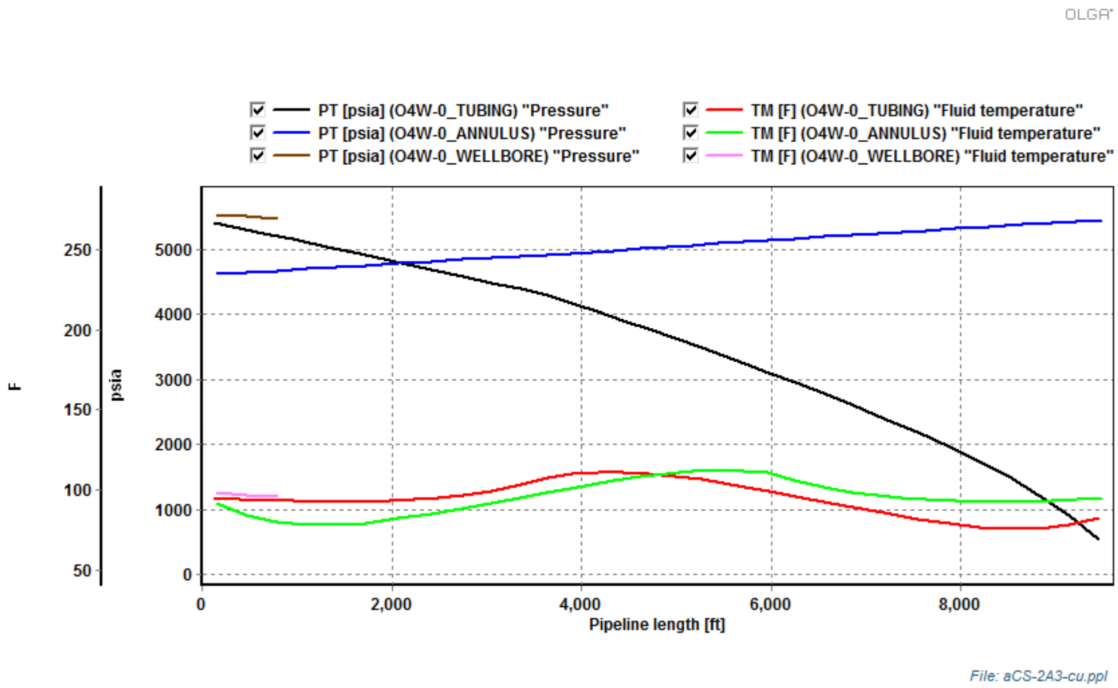


Figure 3.66. Temperature And Pressure At Time=20min Of Unloading Process Profile Plot Case Study 2A3

3.2.3. Case Study 2a4 (60 Deg Deviation). This Case Study describes the behavior of the nitrogen for unloading in a 60 DEG deviated gas well.

3.2.3.1. Survey. Figure 3.67 describes a survey for a 30 DEG deviated well trajectory.

3.2.3.2. Completion design. The completion design is the same as for the base case; the only difference is that the setting depth of the intermediate casing is located at 10550 ft, as shown in Figure 3.68.

3.2.3.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.3.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

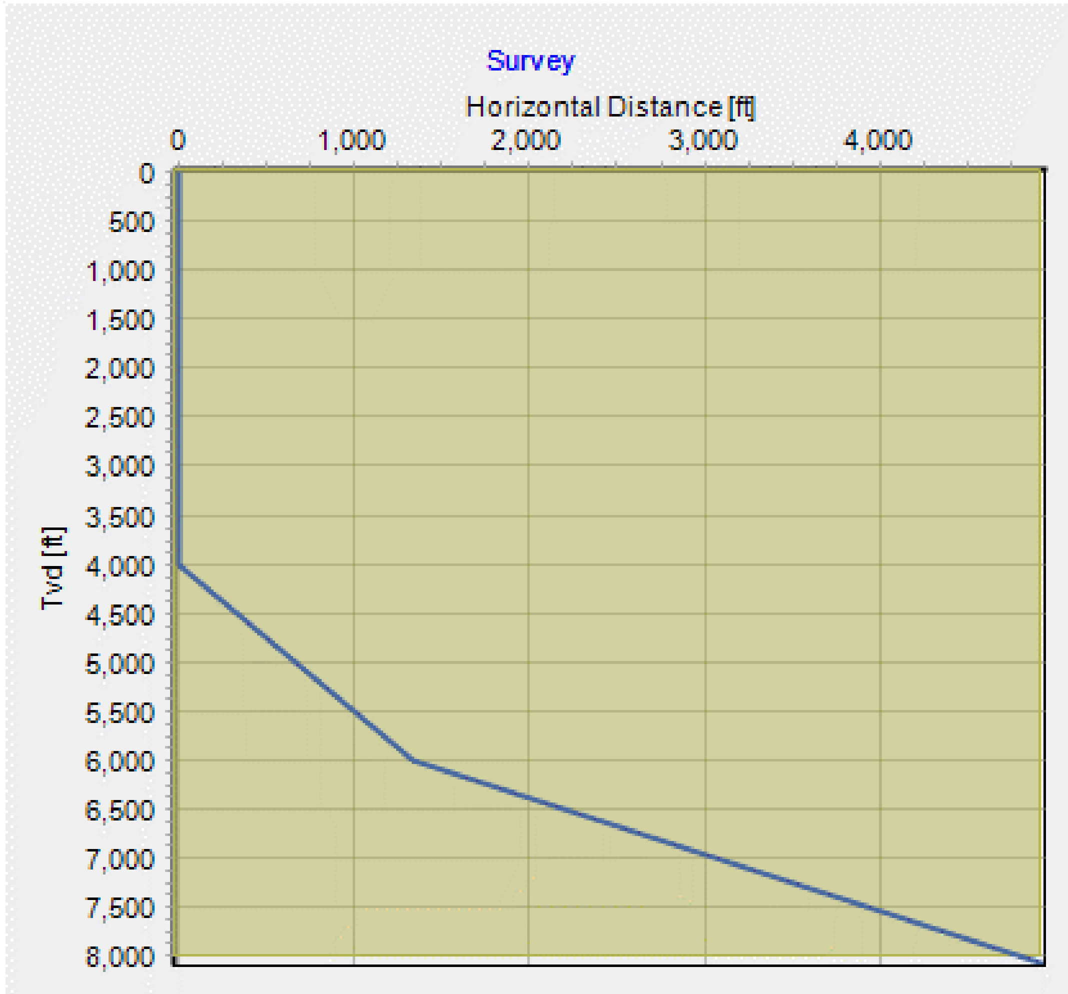


Figure 3.67. Case Study 2A4 60 DEG Deviated Well Survey

This 60 DEG deviated reaches the same pay zone as the Case Study 1A1.

3.2.3.5. Unloading simulation conditions. It follows the same injection flow rate, temperature, pressure and time of injection which was applied to the Case Study 1A1.

3.2.3.1. Results. The following section will show the results for the unloading simulation starting with the hold-up in the tubing, annulus and lateral section of the Case Study 2A4.

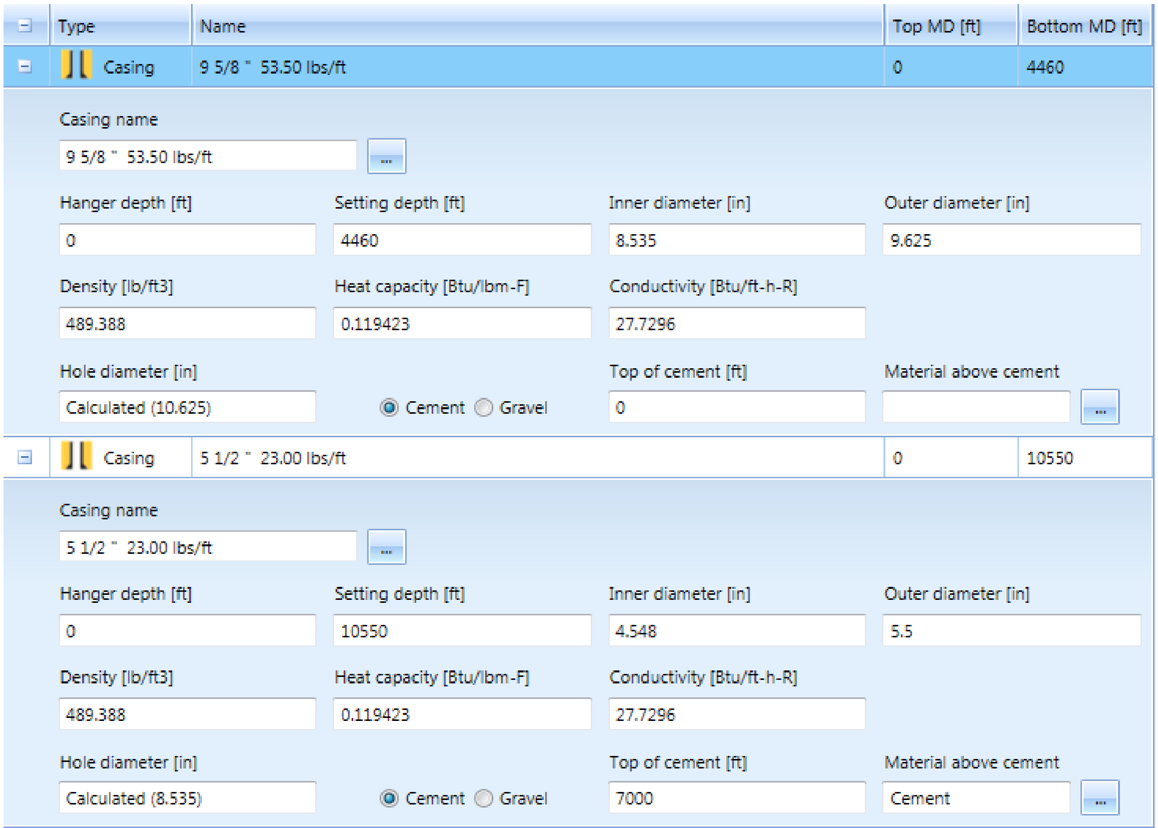


Figure 3.68. Case Study 2A4 Completion Design In Detail

The tubing remains the same as the Case Study 1A1. It reaches 9,606 ft from the surface.

3.2.3.2. Hold-Up. Figure 3.69 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process starts.

Figure 3.70 shows the hold-up for the tubing, annulus and lateral section in a 3D model.

Figure 3.71 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 10min.

Figure 3.72 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 10min of injection.

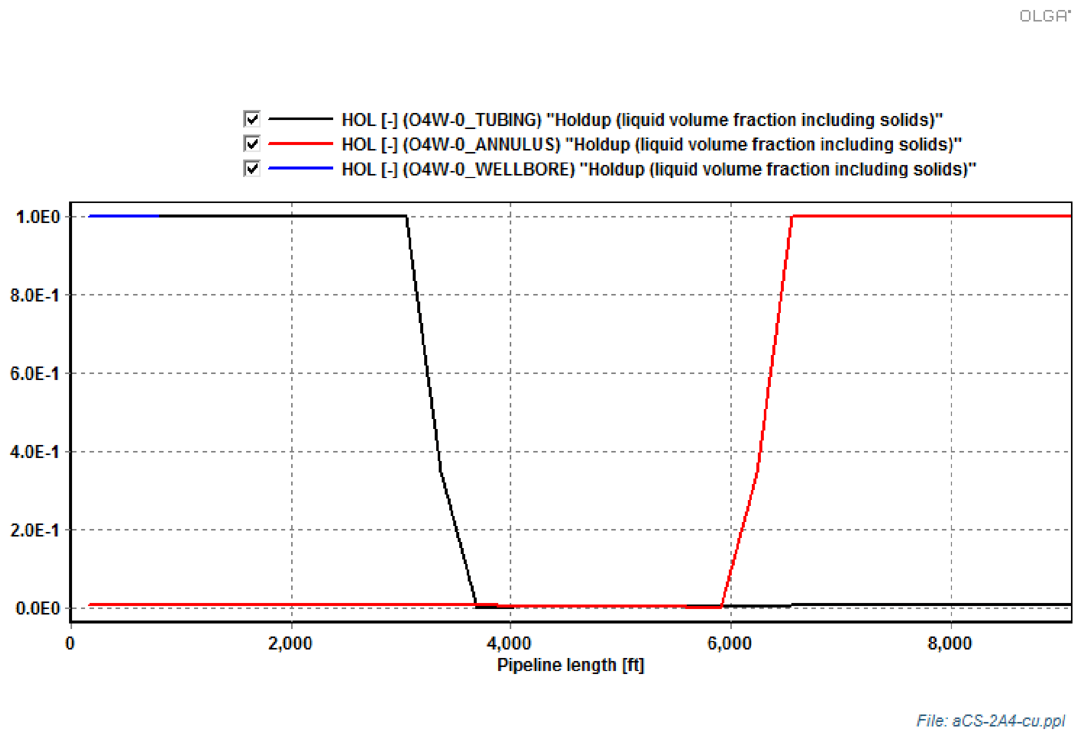


Figure 3.69. Hold-Up At Time=0min Of Unloading Process Profile Plot Case Study 2A4

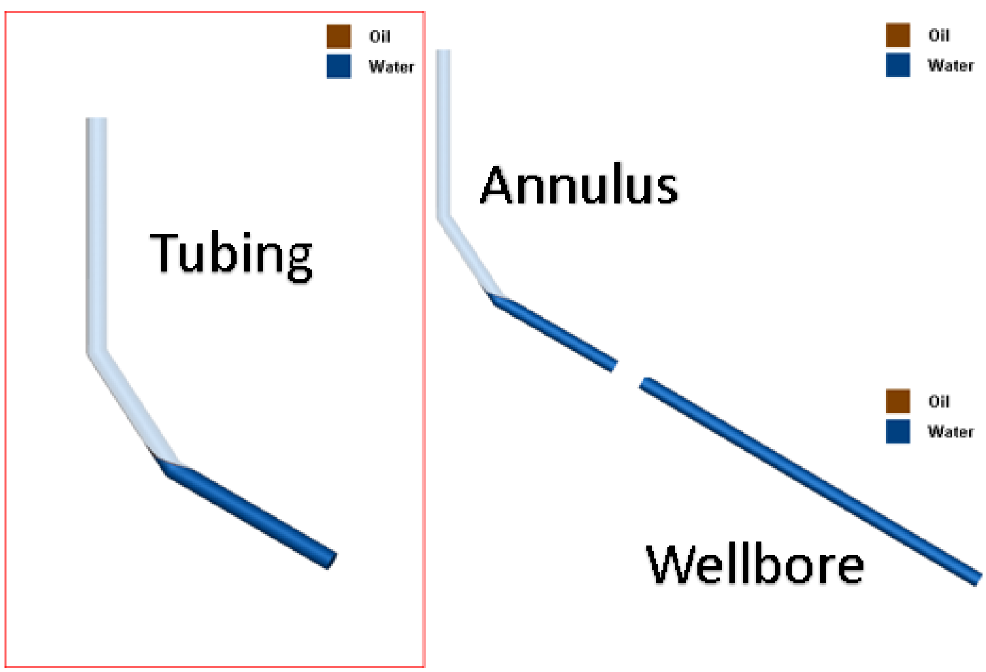


Figure 3.70. Hold-Up At Time=0min Of Unloading Process 3D Plot Case Study 2A4

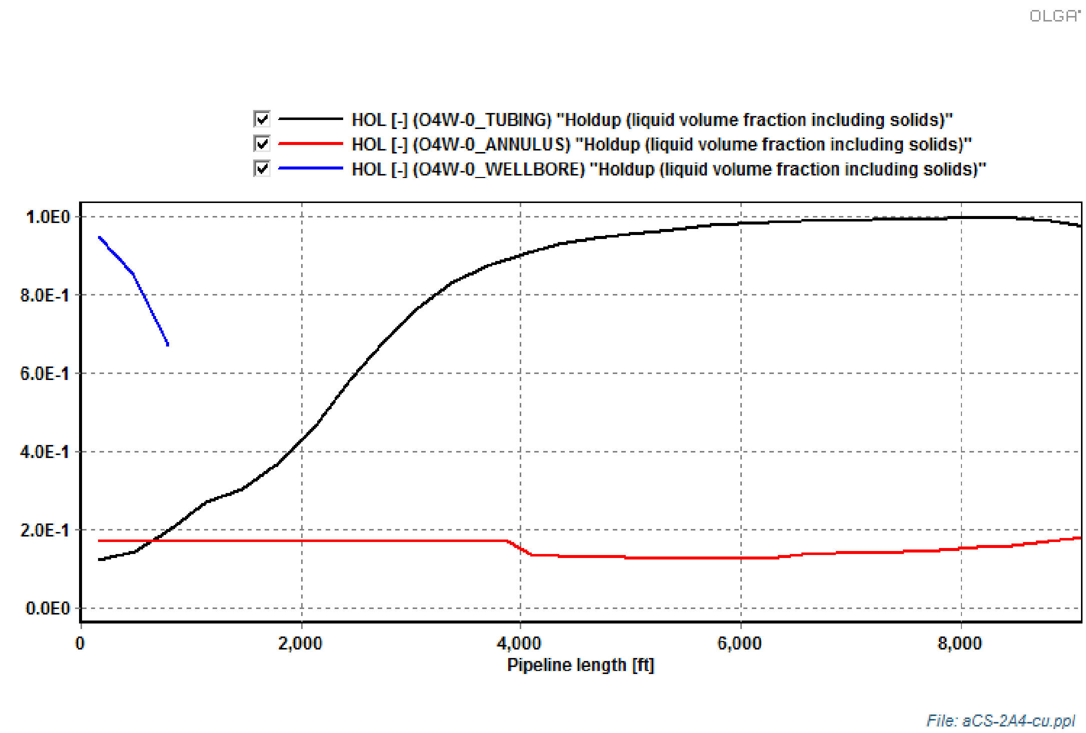


Figure 3.71. Hold-Up At Time=10min Of Unloading Process Profile Plot Case Study 2A4

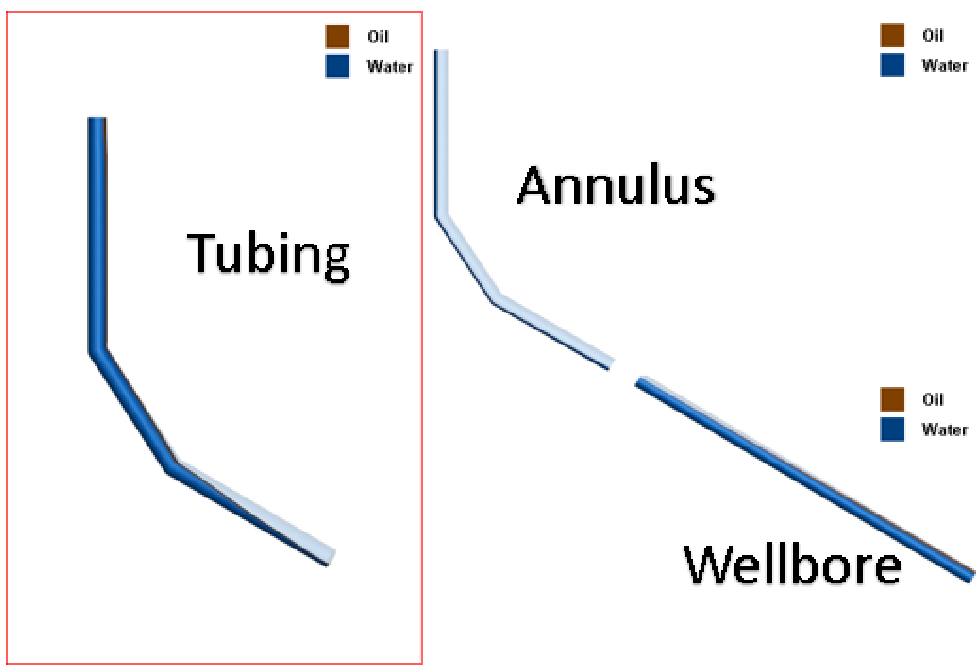


Figure 3.72. Hold-Up At Time=10min Of Unloading Process 3D Plot Case Study 2A4

Figure 3.73 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 20min.

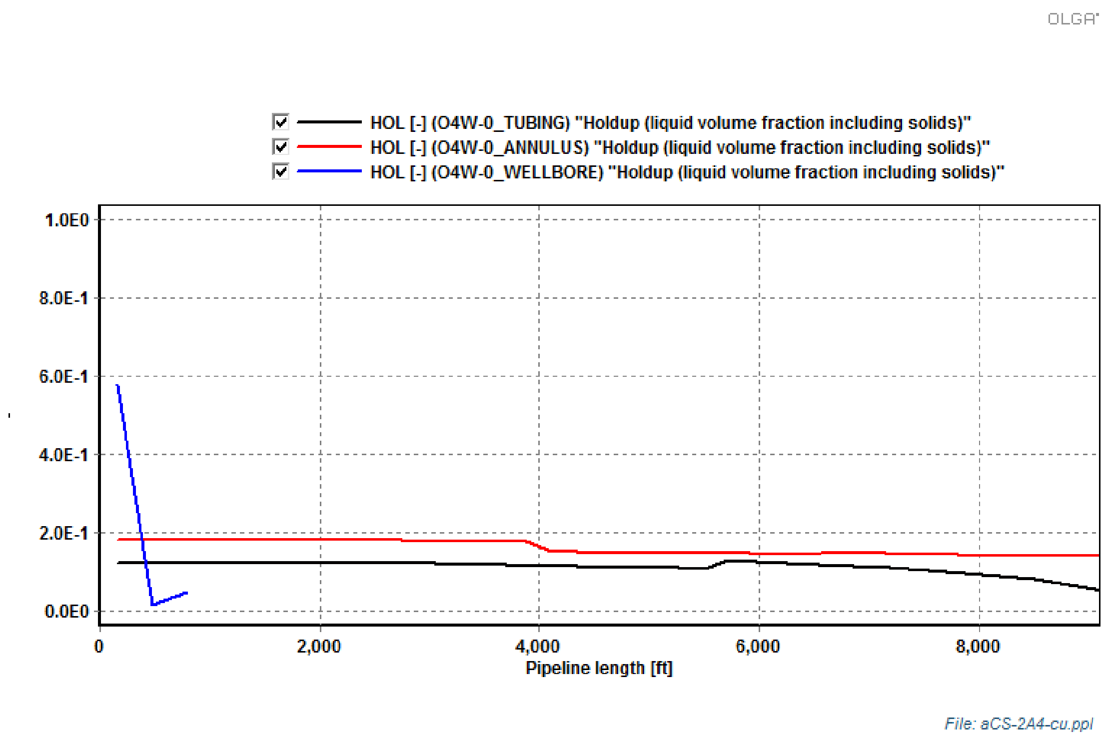


Figure 3.73. Hold-Up At Time=20min Of Unloading Process Profile Plot Case Study 2A4

Figure 3.74 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 20min of injection.

3.2.3.3. Temperature and pressure. In this section, the temperature and pressure are plotted for Case Study 2A4.

Figure 3.75 details the pressure and temperature at the tubing, annulus and lateral section of the wellbore when the unloading process starts. Figure 3.76 shows the same parameters after 10min of injection.

Figure 3.77 shows the same parameters after 20min of injection.

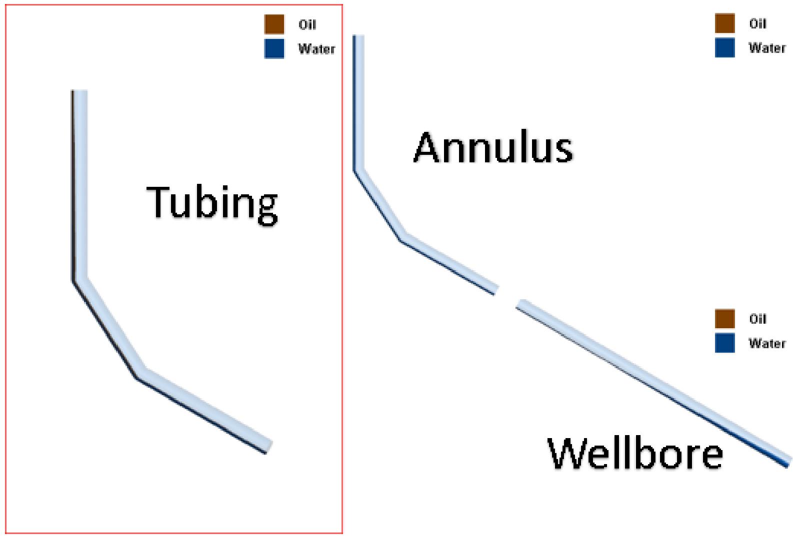


Figure 3.74. Hold-Up At Time=20min Of Unloading Process 3D Plot Case Study 2A4

Within the first 20 minutes, the well is completely unloaded. The same behavior is observed in Case Study 2A3.

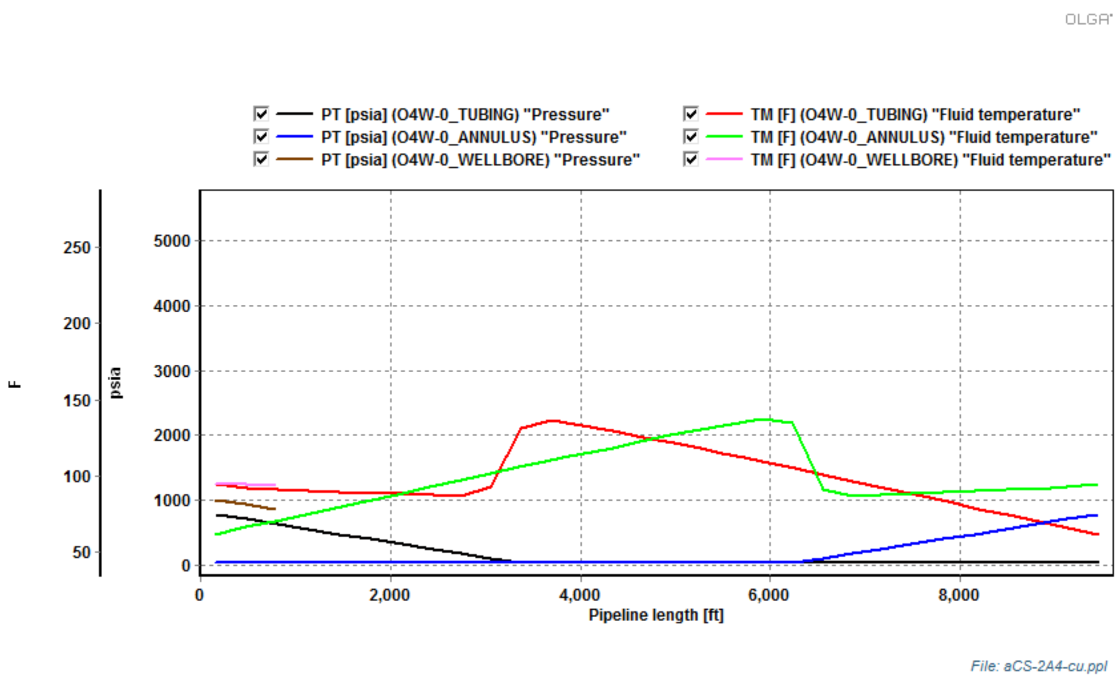


Figure 3.75. Temperature And Pressure At Time=0min Of Unloading Process Profile Plot Case Study 2A4

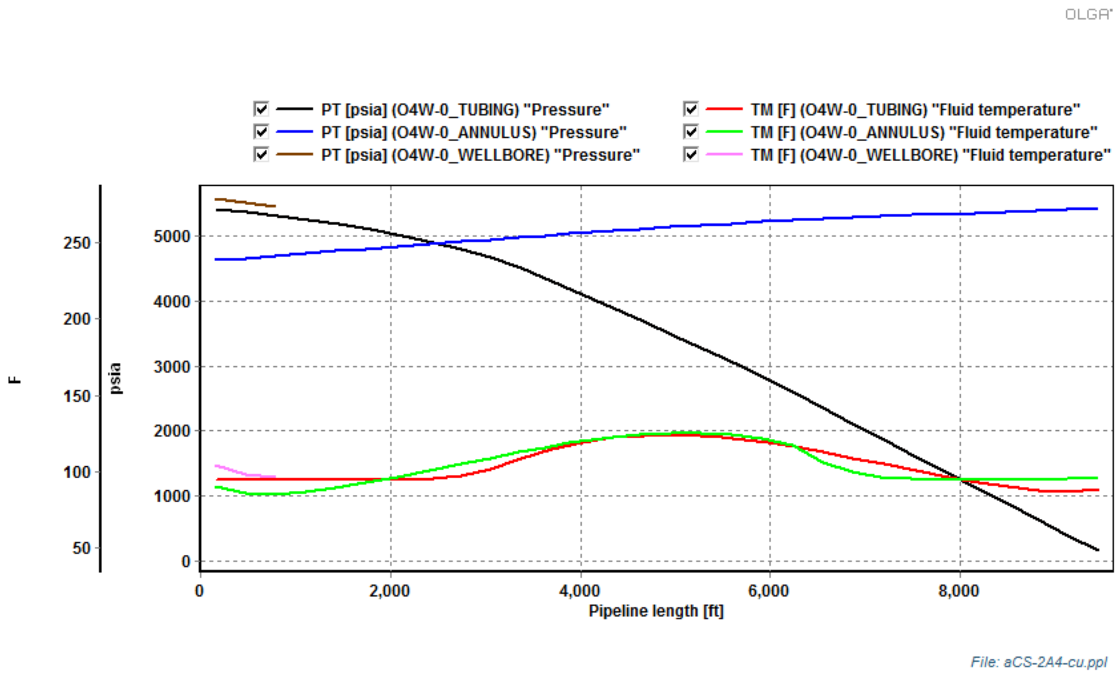


Figure 3.76. Temperature And Pressure At Time=10min Of Unloading Process Profile Plot Case Study 2A4

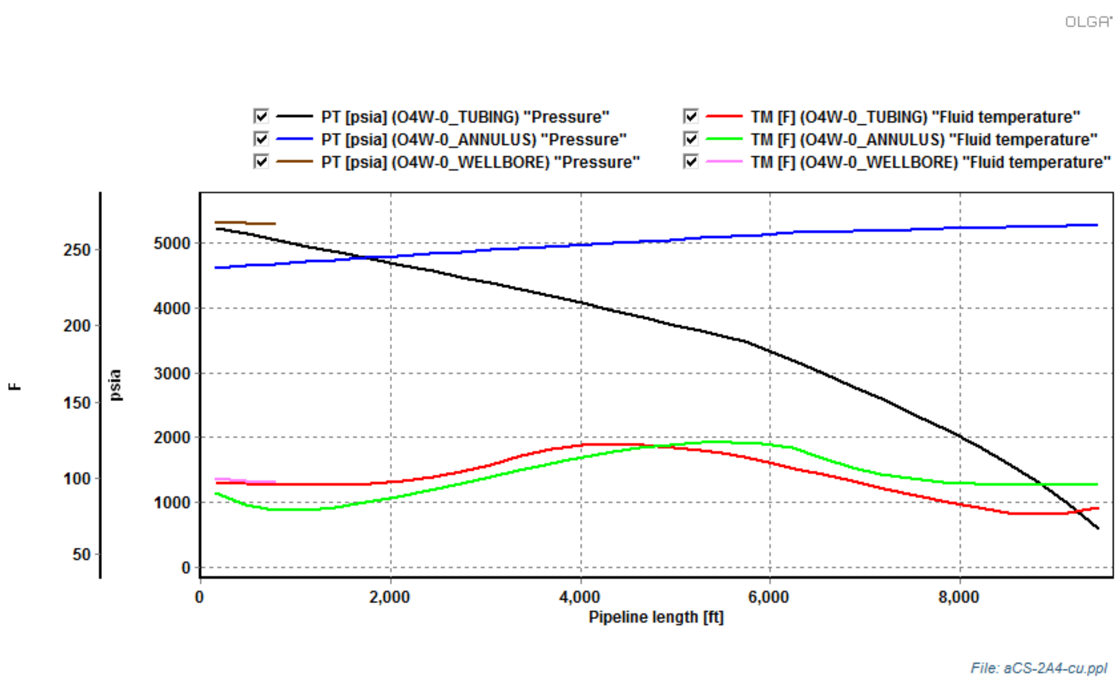


Figure 3.77. Temperature And Pressure At Time=20min Of Unloading Process Profile Plot Case Study 2A4

The previous section described the behavior of nitrogen for unloading gas wells when well survey differs from the vertical particularly in three cases, starting from a vertical well, then 30 DEG deviated well and finishing with a 60 DEG deviated well.

The following section investigates the effect of non-Newtonian frac hit fluids in the unloading gas well technique, using parameters recommended by Baker Hughes.

The next cases of study use the same configuration as Case Study 1A1 regarding initial conditions, level of fluid, survey and nitrogen injection parameters.

However, each case will deal with a different type of frac fluid.

3.2.4. Case Study 2B5 (Slick-Water Plastic Viscosity 1.85cP). This Case Study describes the behavior of the nitrogen for unloading in a gas well that was loaded by slickwater as a frac fluid with a plastic viscosity of 1.85cP.

3.2.4.1. Survey. Figure 3.78 describes the survey for a horizontal well trajectory. The gas well survey is taken from Case Study 1A1.

3.2.4.2. Completion design. The completion design is the same as for the base case as shown in Figure 3.79.

The tubing remains the same as the Case Study 1A1. It reaches 9,606 ft from the surface.

3.2.4.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.4.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.4.5. Unloading simulation conditions. It follows the same injection flow rate, temperature, pressure and time of injection which was applied to the Case Study 1A1.

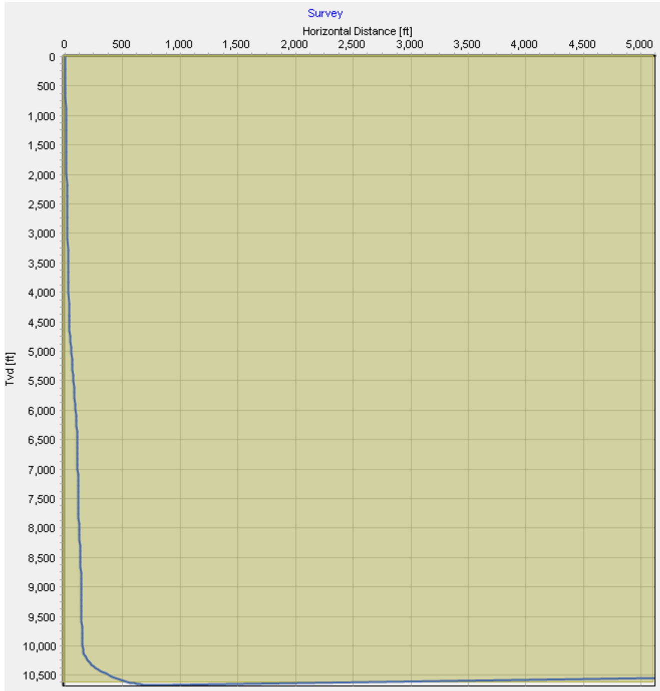


Figure 3.78. Case Study 2B5 Well Survey

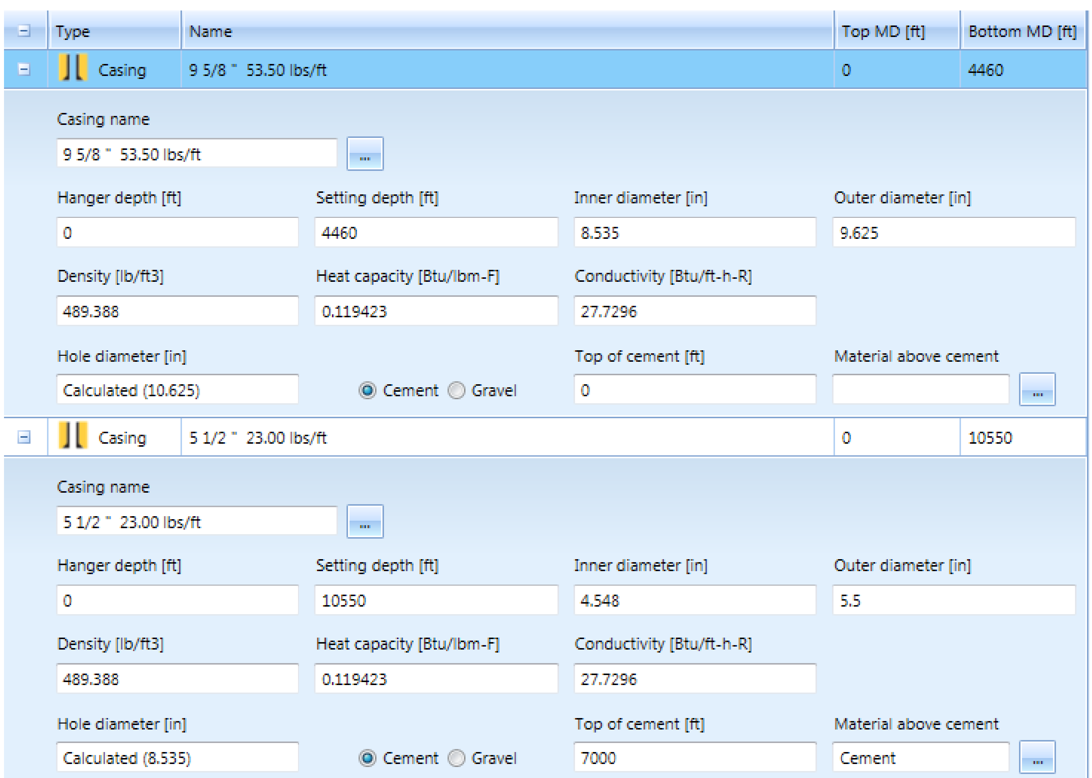


Figure 3.79. Case Study 2B5 Completion Design In Detail

3.2.4.6. Results. The following section will show the results for the unloading simulation starting with the hold-up in the tubing, annulus and lateral section of the Case Study 2B5.

3.2.4.7. Hold-Up. Figure 3.80 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process starts.

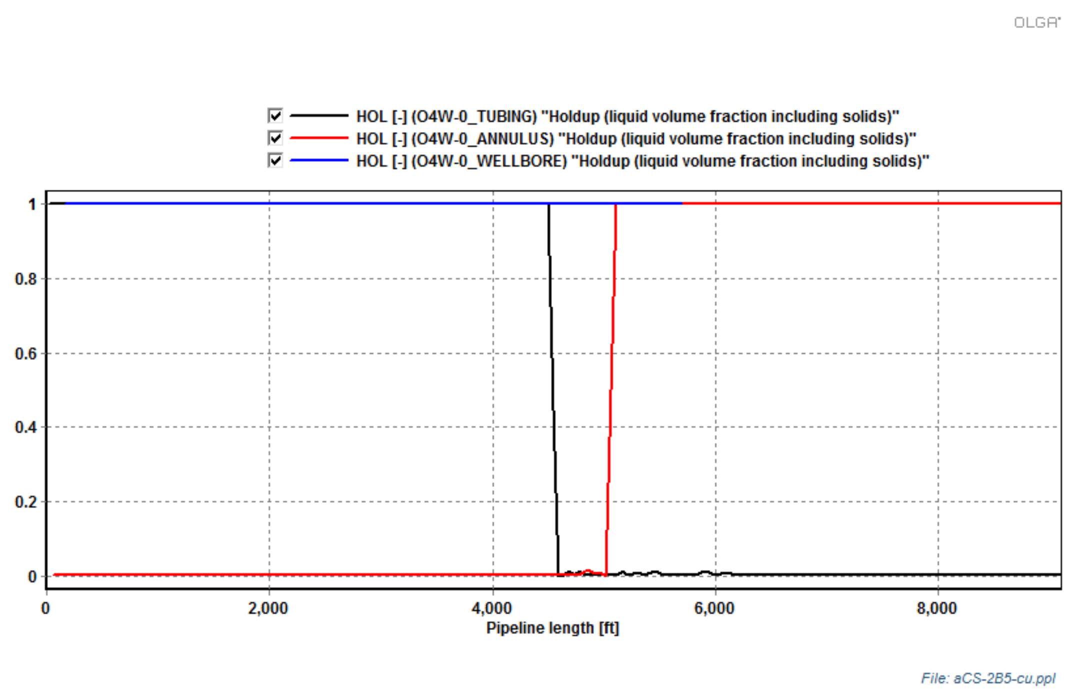


Figure 3.80. Hold-Up At Time=0min Of Unloading Process Profile Plot Case Study 2B5

Figure 3.81 shows the hold-up for the tubing, annulus and lateral section in a 3D model.

Figure 3.82 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 10min.

Figure 3.83 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 10min of injection.

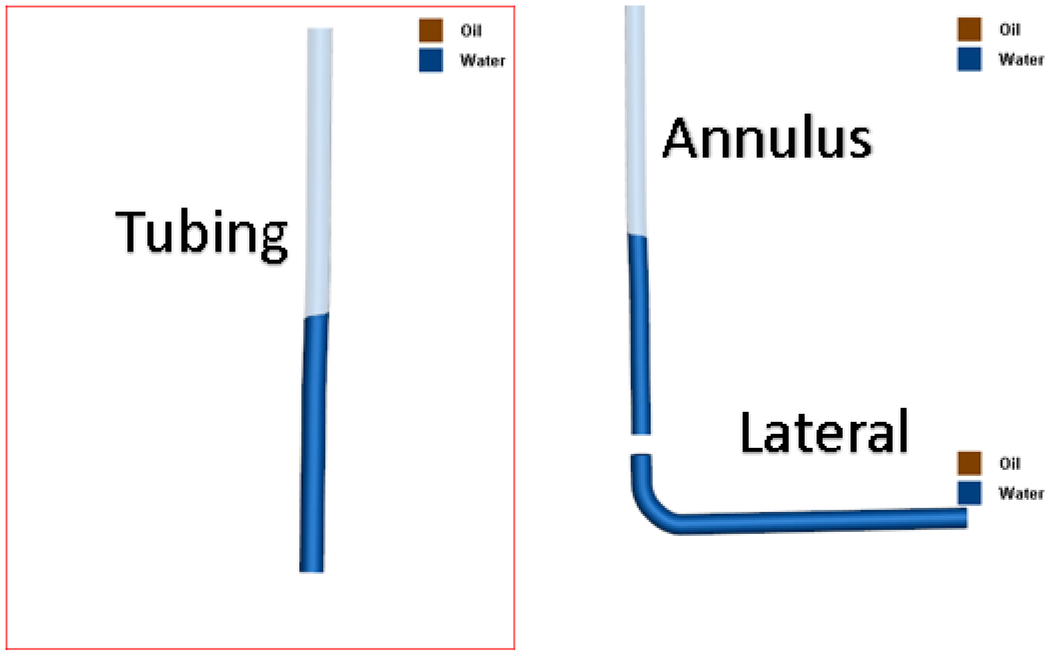


Figure 3.81. Hold-Up At Time=0min Of Unloading Process 3D Plot Case Study 2B5

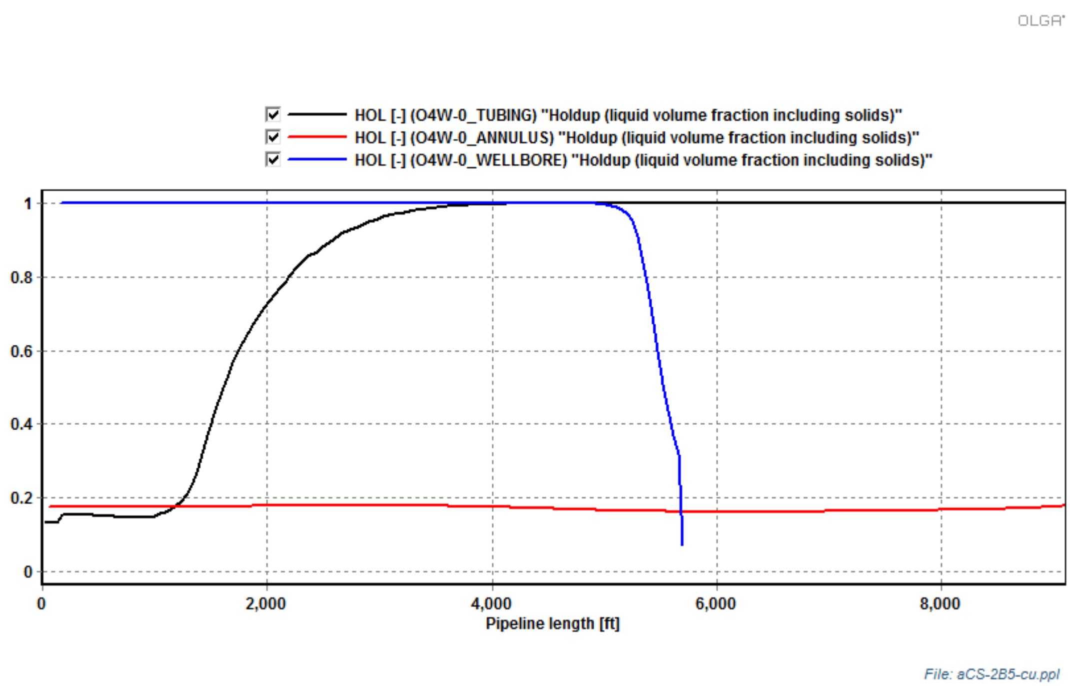


Figure 3.82. Hold-Up At Time=10min Of Unloading Process Profile Plot Case Study 2B5

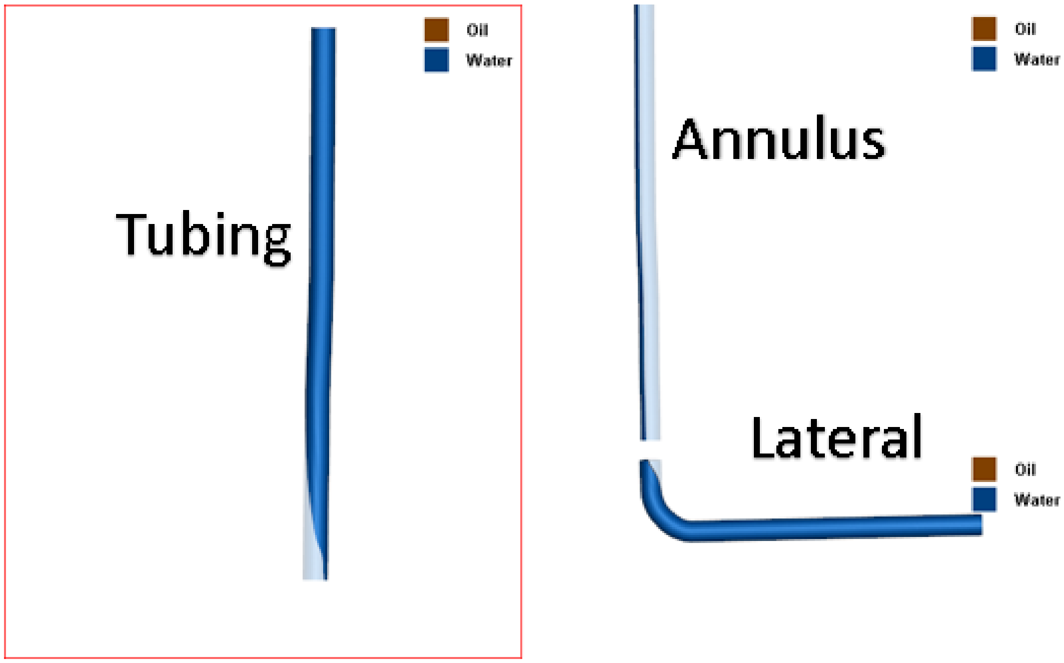


Figure 3.83. Hold-Up At Time=10min Of Unloading Process 3D Plot Case Study 2B5

Figure 3.84 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 20min.

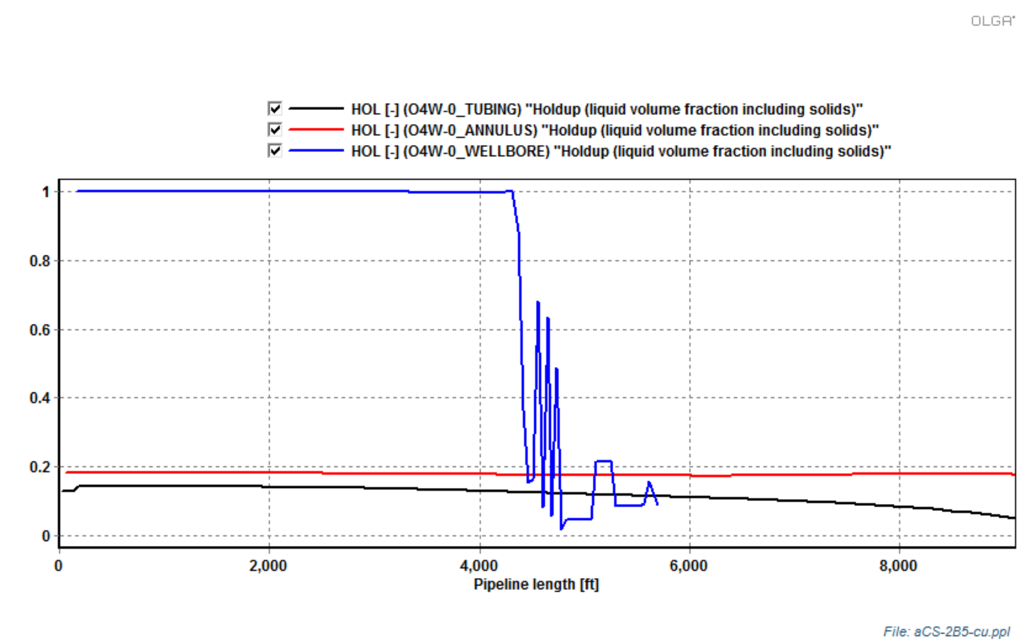


Figure 3.84. Hold-Up At Time=20min Of Unloading Process Profile Plot Case Study 2B5

Figure 3.85 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 20min of injection.

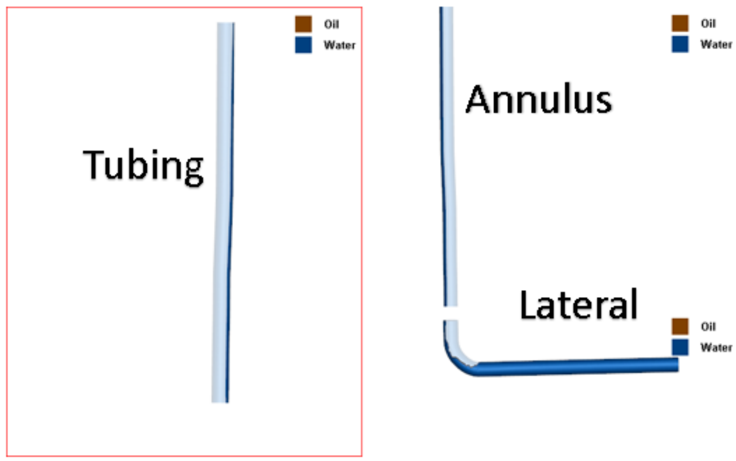


Figure 3.85. Hold-Up At Time=20min Of Unloading Process 3D Plot Case Study 2B5

Figure 3.86 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 30min.

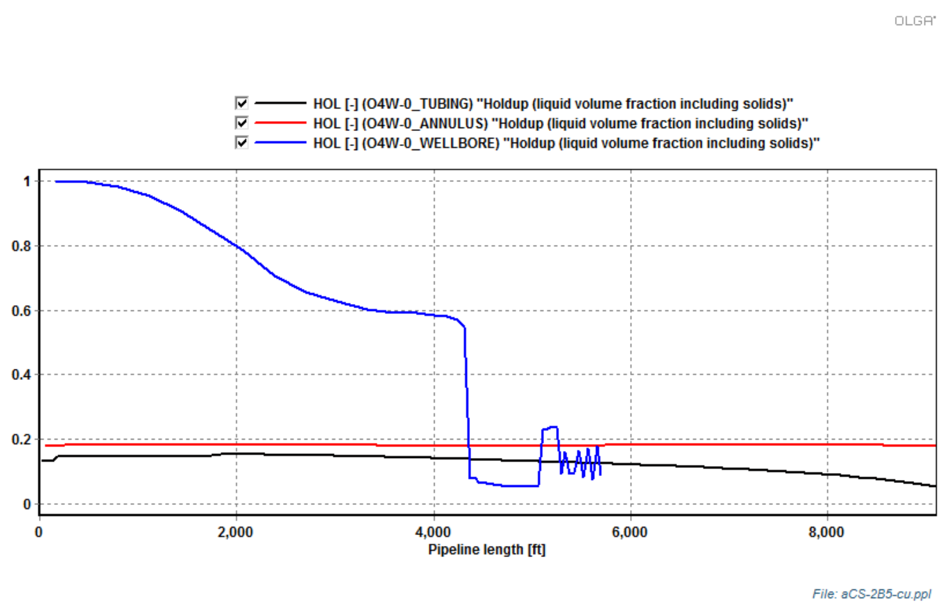


Figure 3.86. Hold-Up At Time=30min Of Unloading Process Profile Plot Case Study 2B5

Figure 3.87 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 30min of injection.

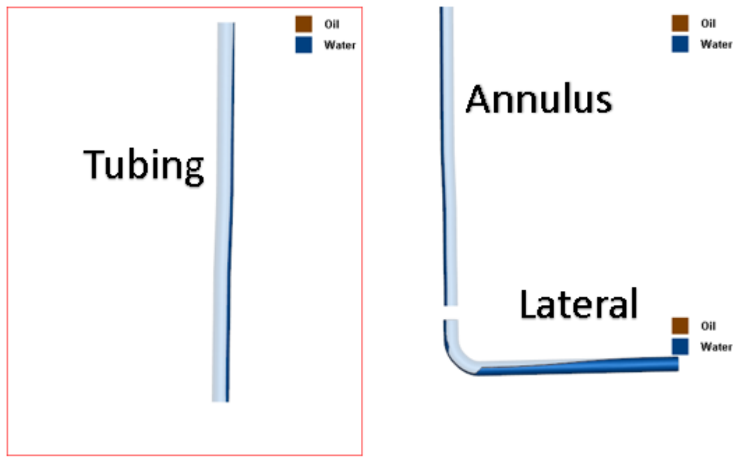


Figure 3.87. Hold-Up At Time=30min Of Unloading Process 3D Plot Case Study 2B5

Figure 3.88 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 60min.

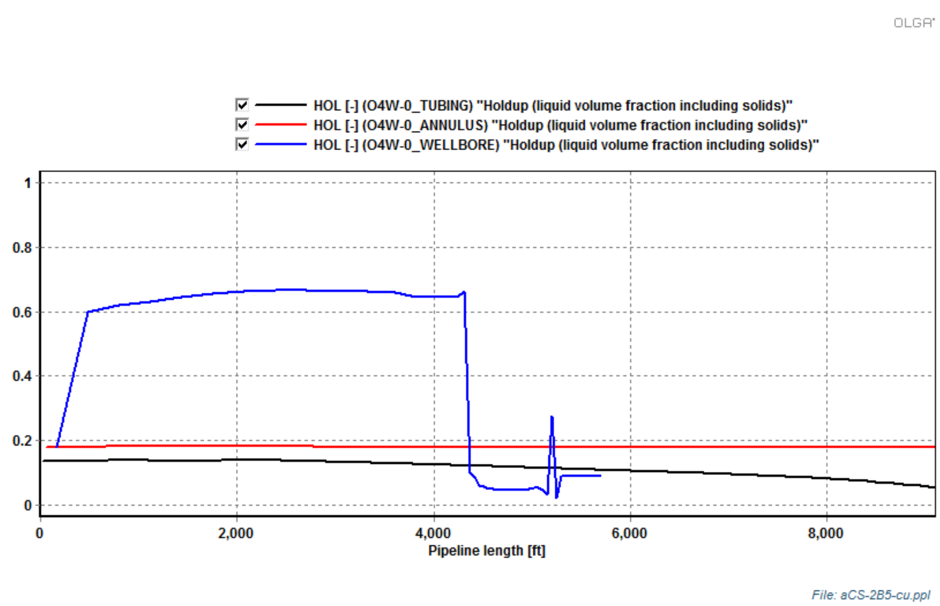


Figure 3.88. Hold-Up At Time=60min Of Unloading Process Profile Plot Case Study 2B5

Figure 3.89 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 60min of injection.

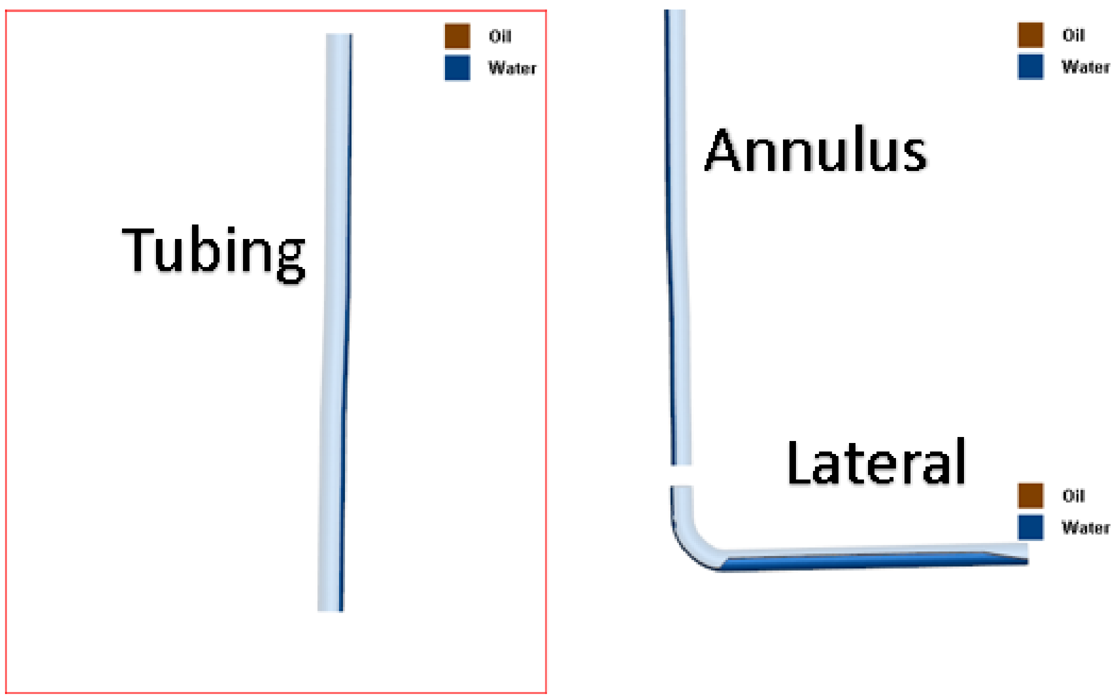


Figure 3.89. Hold-Up At Time=60min Of Unloading Process 3D Plot Case Study 2B5

After this time, the nitrogen injection stops allowing the reservoir to produce gas naturally.

3.2.4.8. Temperature and pressure. In this section, the temperature and pressure are plotted for Case Study 2B5.

Figure 3.90 details the pressure and temperature at the tubing, annulus and lateral section of the wellbore when the unloading process starts.

Figure 3.91 shows the same parameters after 20min of injection. Figure 3.92 shows the same parameters after 60min of injection.

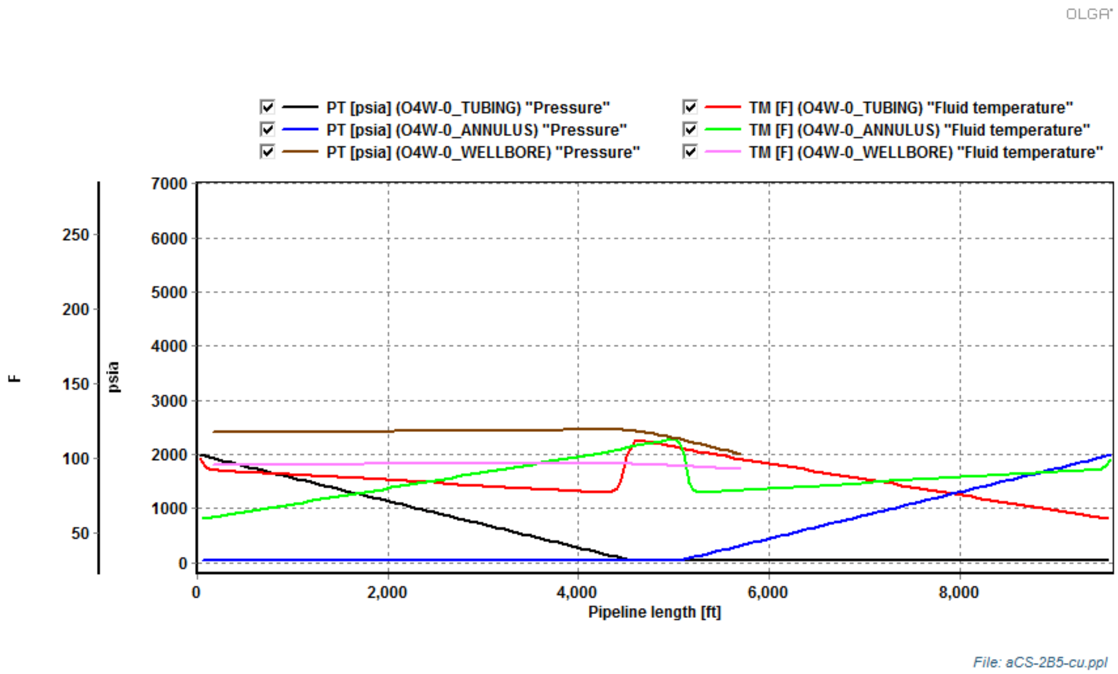


Figure 3.90. Temperature And Pressure At Time=0min Of Unloading Process Profile Plot Case Study 2B5

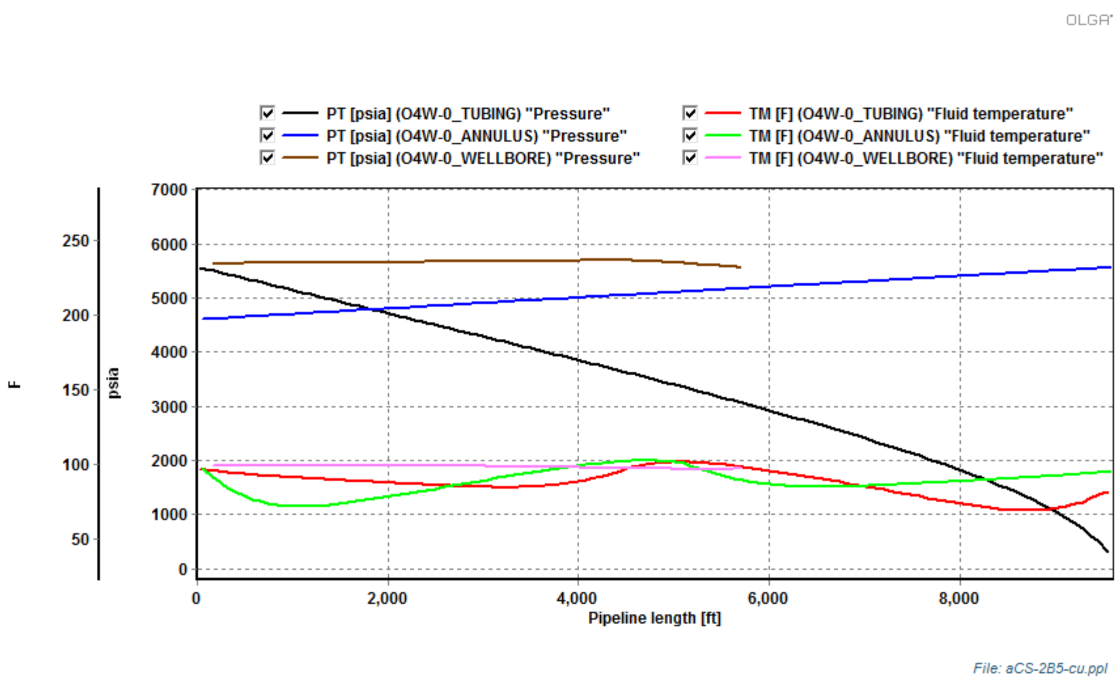


Figure 3.91. Temperature And Pressure At Time=20min Of Unloading Process Profile Plot Case Study 2B5

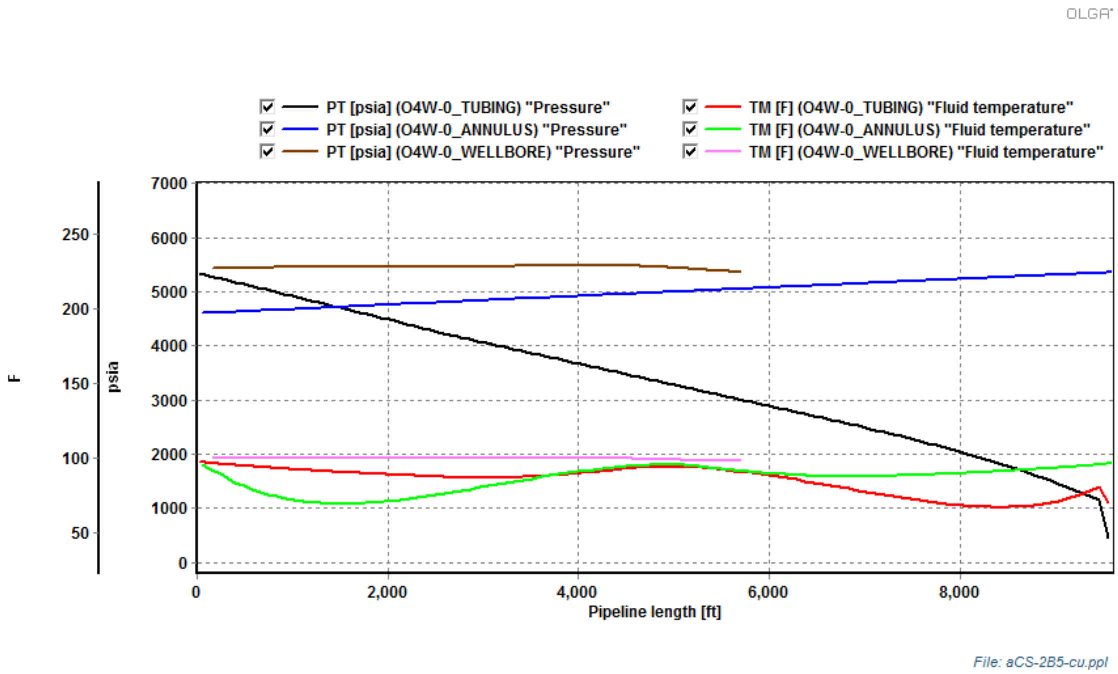


Figure 3.92. Temperature And Pressure At Time=60min Of Unloading Process Profile Plot Case Study 2B5

3.2.5. Case Study 2B6 (Gel#20 Plastic Viscosity 24cP). This Case Study describes the behavior of the nitrogen for unloading in a gas well that was loaded by Gel#20 as a frac fluid with a plastic viscosity of 24cP.

3.2.5.1. Survey. Figure 3.93 describes the survey for a horizontal well trajectory. The gas well survey is taken from Case Study 1A1.

3.2.5.1. Completion design. The completion design is the same as for the base case as shown in Figure 3.94.

The tubing remains the same as the Case Study 1A1. It reaches 9,606 ft from the surface.

3.2.5.2. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

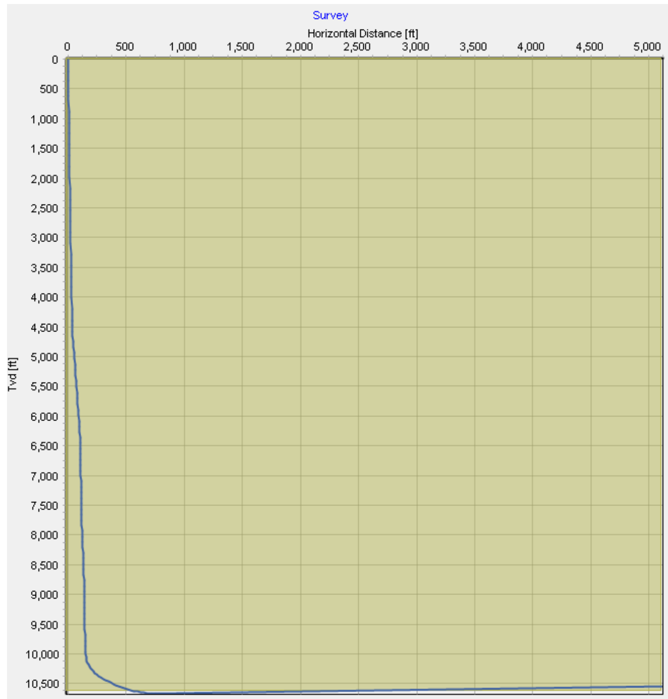


Figure 3.93. Case Study 2B6 Well Survey

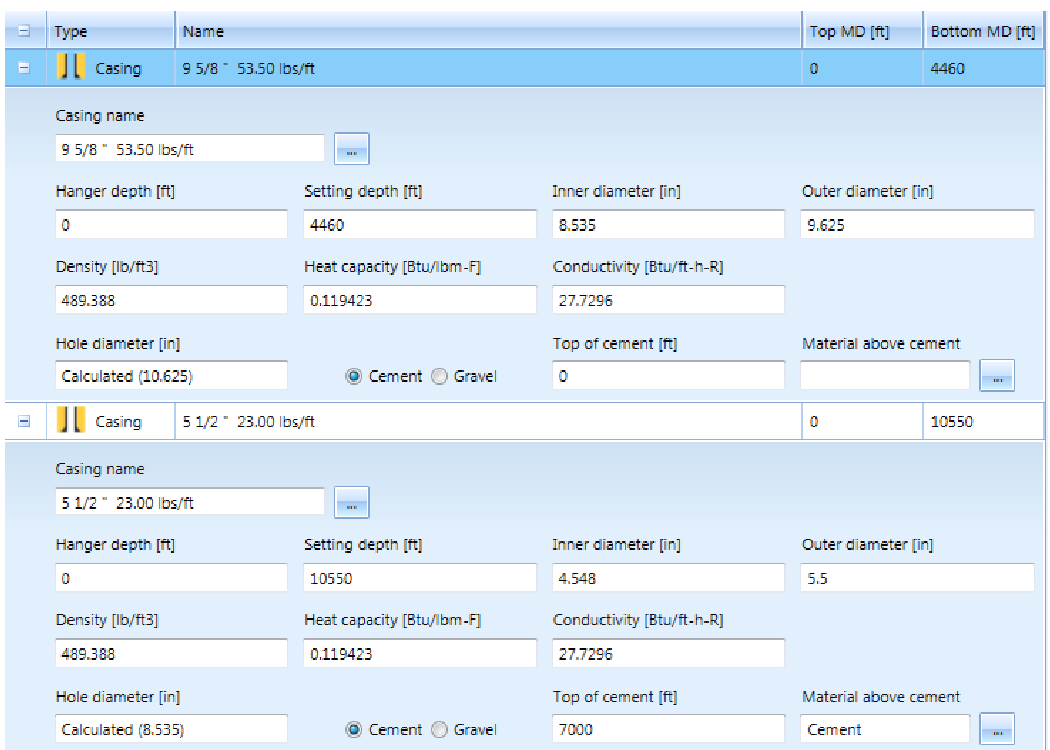


Figure 3.94. Case Study 2B6 Completion Design In Detail

3.2.5.3. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.5.4. Unloading simulation conditions. It follows the same injection flow rate, temperature, pressure and time of injection which was applied to the Case Study 1A1.

3.2.5.5. Results. The following section will show the results for the unloading simulation starting with the hold-up in the tubing, annulus and lateral section of the Case Study 2B6.

3.2.5.6. Hold-Up. Figure 3.95 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process starts.

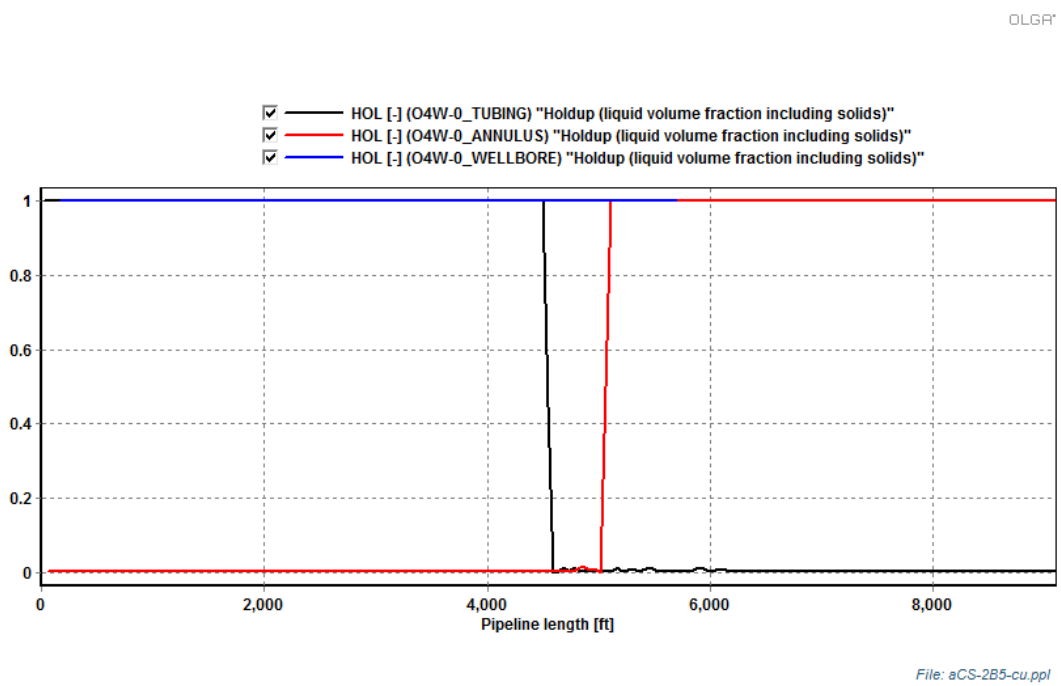


Figure 3.95. Hold-Up At Time=0min Of Unloading Process Profile Plot Case Study 2B6

Figure 3.96 shows the hold-up for the tubing, annulus and lateral section in a 3D model.

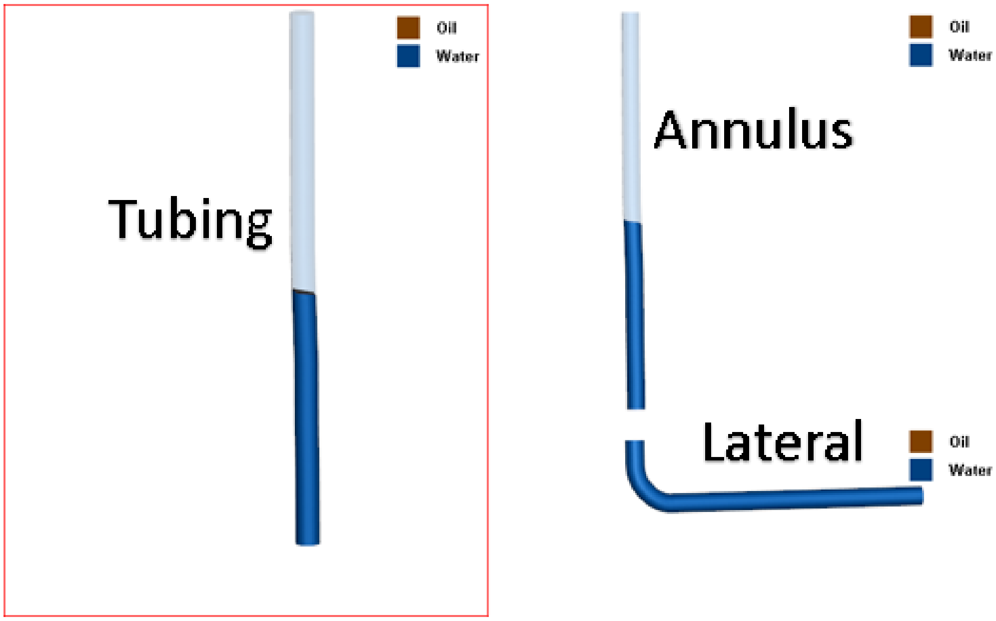


Figure 3.96. Hold-Up At Time=0min Of Unloading Process 3D Plot Case Study 2B6

Figure 3.97 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 10min.

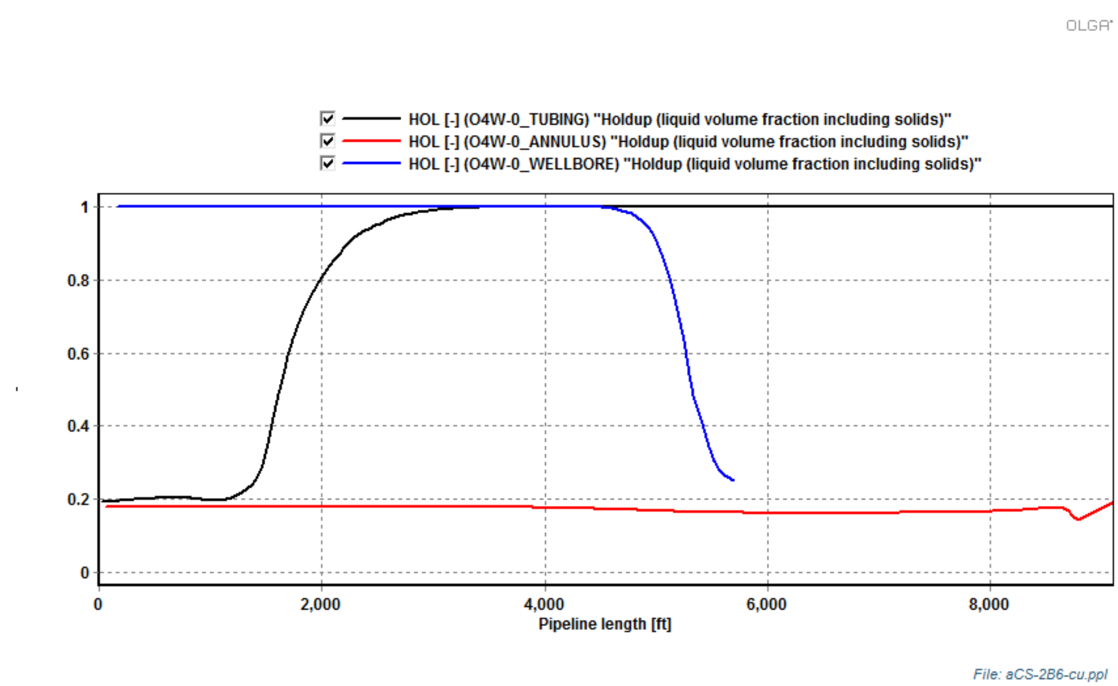


Figure 3.97. Hold-Up At Time=10min Of Unloading Process Profile Plot Case Study 2B6

Figure 3.98 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 10min of injection.

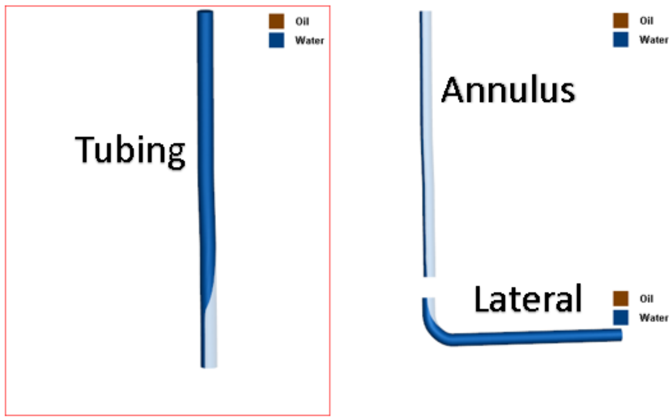


Figure 3.98. Hold-Up At Time=10min Of Unloading Process 3D Plot Case Study 2B6

Figure 3.99 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 20min.

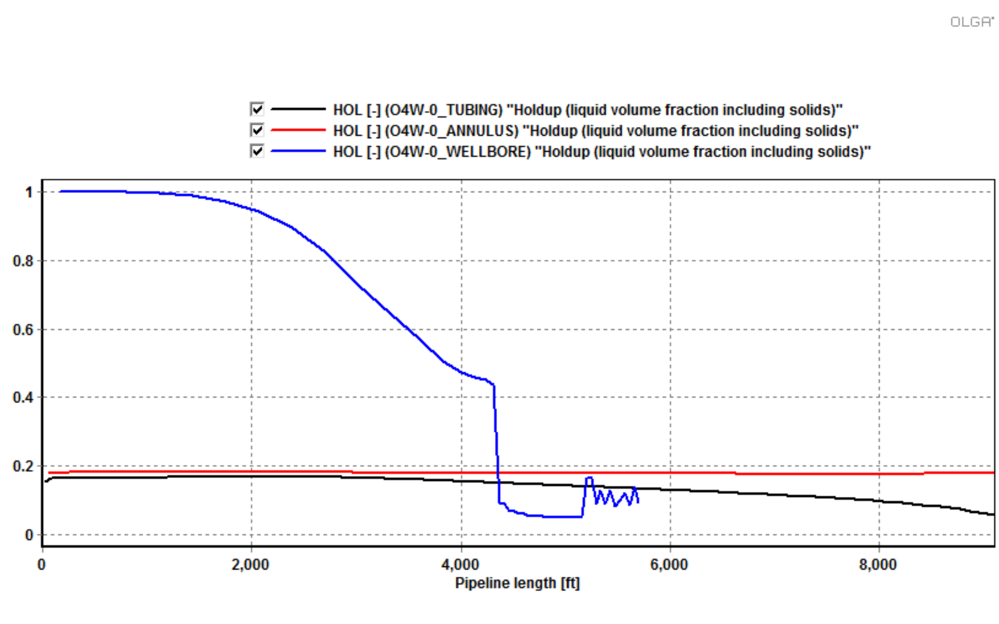


Figure 3.99. Hold-Up At Time=20min Of Unloading Process Profile Plot Case Study 2B6

Figure 3.100 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 20min of injection.

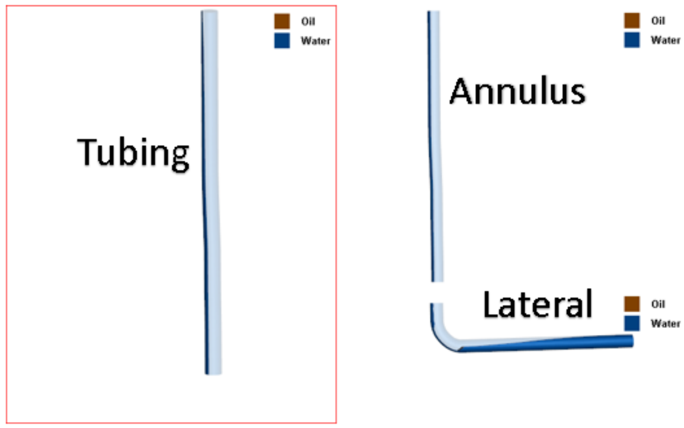


Figure 3.100. Hold-Up At Time=20min Of Unloading Process 3D Plot Case Study 2B6

Figure 3.101 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 60min.

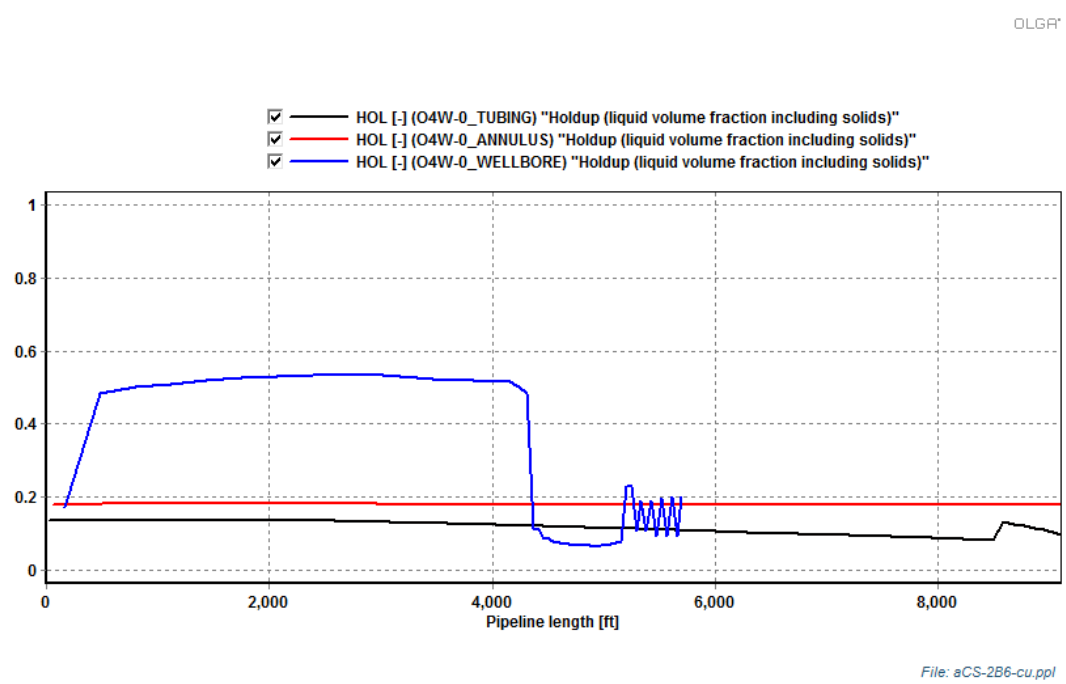


Figure 3.101. Hold-Up At Time=60min Of Unloading Process Profile Plot Case Study 2B6

Figure 3.102 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 60min of injection.

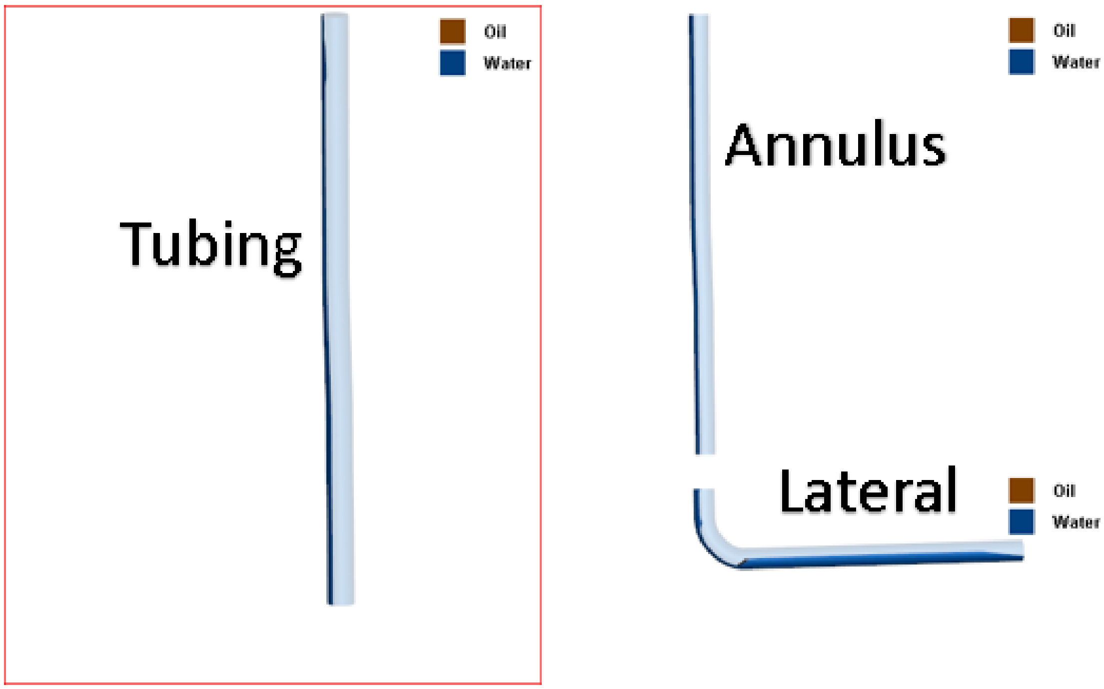


Figure 3.102. Hold-Up At Time=60min Of Unloading Process 3D Plot Case Study 2B6

After this time, the nitrogen injection stops allowing the reservoir to produce gas naturally.

3.2.5.7. Temperature and pressure. In this section, the temperature and pressure are plotted for Case Study 2B6.

Figure 3.103 details the pressure and temperature at the tubing, annulus and lateral section of the wellbore when the unloading process starts. Figure 3.104 shows the same parameters after 20min of injection. Figure 3.105 shows the same parameters after 60min of injection.

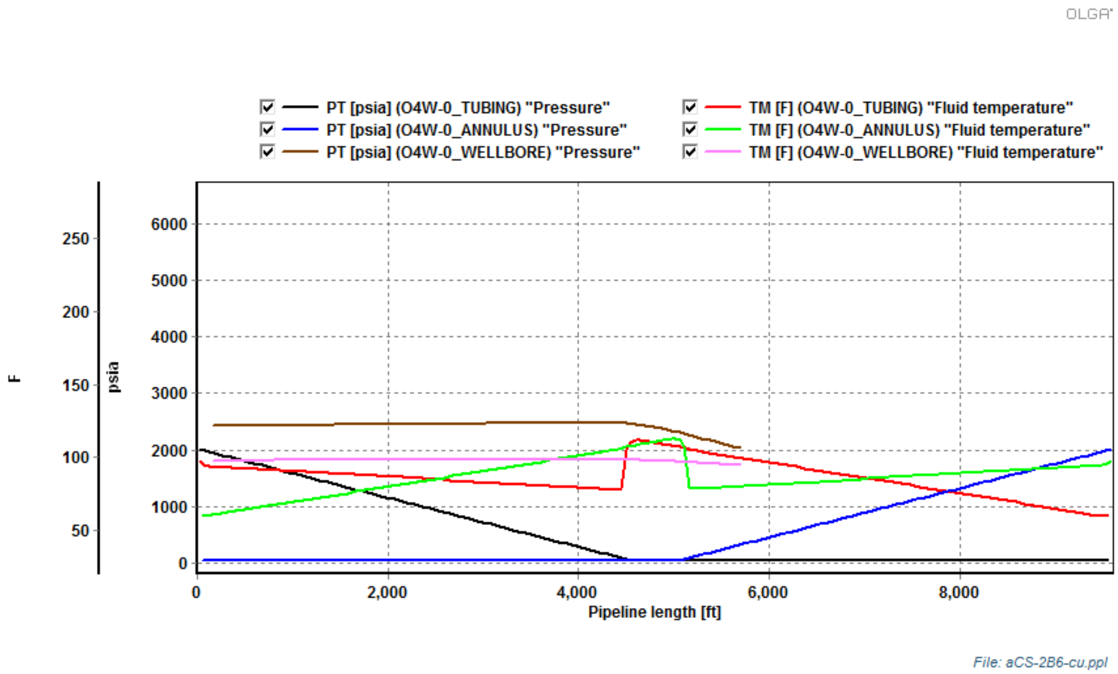


Figure 3.103. Temperature And Pressure At Time=0min Of Unloading Process Profile Plot Case Study 2B6

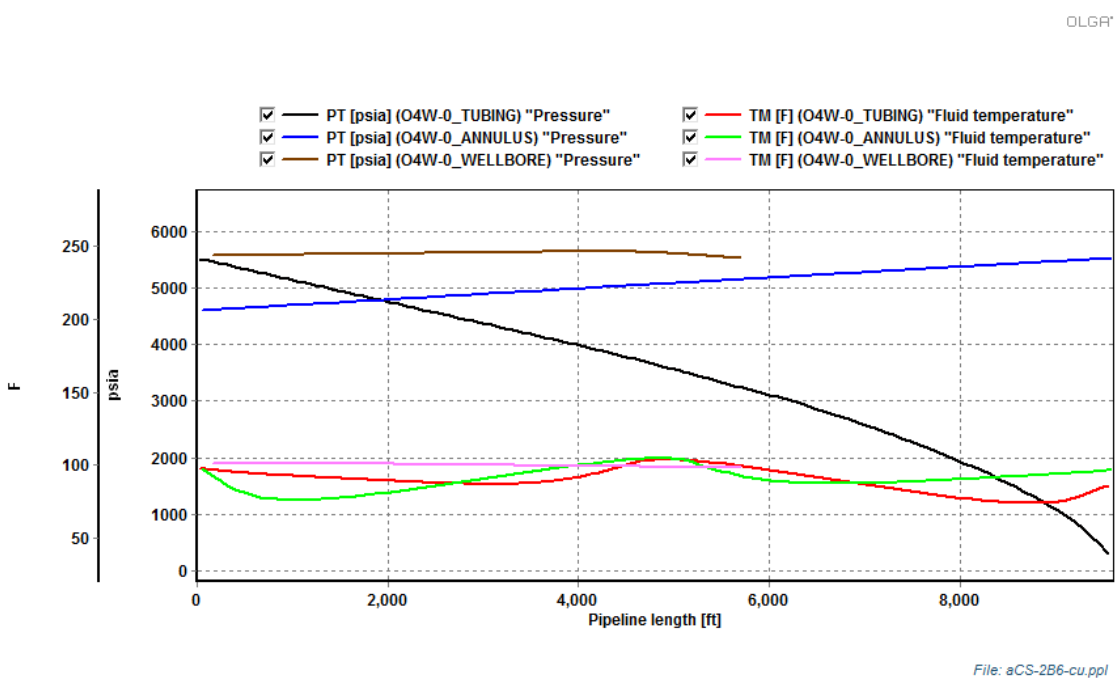


Figure 3.104. Temperature And Pressure At Time=20min Of Unloading Process Profile Plot Case Study 2B6

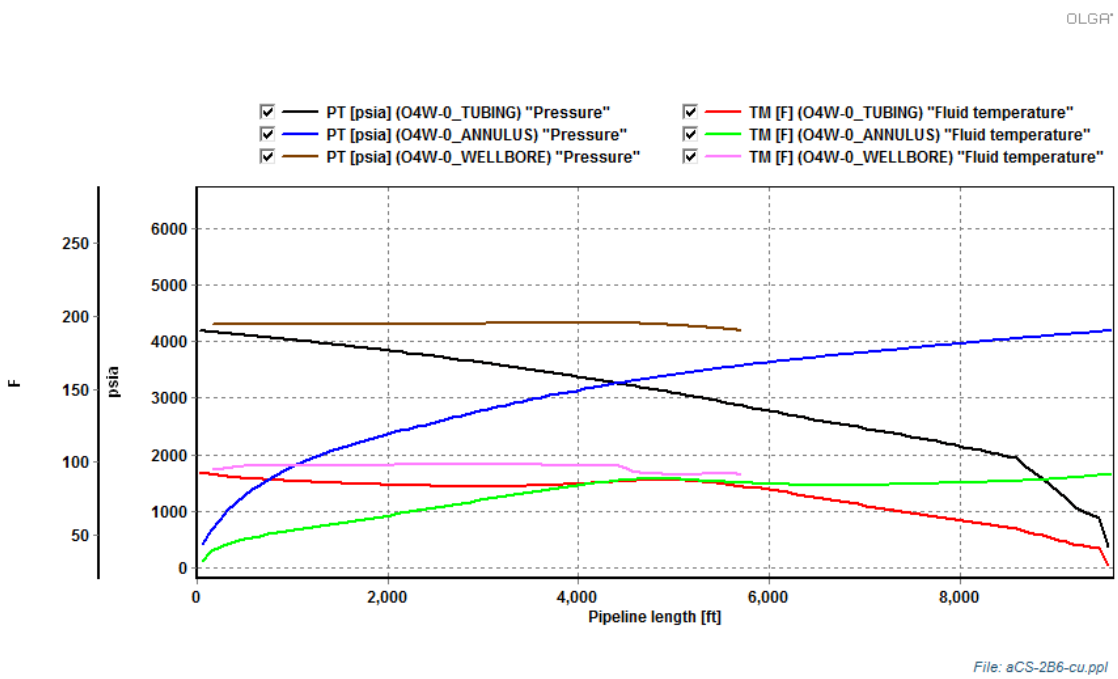


Figure 3.105. Temperature And Pressure At Time=60min Of Unloading Process Profile Plot Case Study 2B6

3.2.6. Case Study 2B7 (Slick-Water + Friction Reducer MP20A01 Plastic Viscosity 1.5cP). This Case Study describes the behavior of the nitrogen for unloading in a gas well that was loaded by slickwater + friction reducer MP20A01 as a frac fluid with a plastic viscosity of 1.5cP.

3.2.6.1. Survey. Figure 3.106 describes the survey for a horizontal well trajectory. The gas well survey is taken from Case Study 1A1.

3.2.6.2. Completion design. The completion design is the same as for the base case as shown in Figure 3.107.

The tubing remains the same as the Case Study 1A1. It reaches 9,606 ft from the surface.

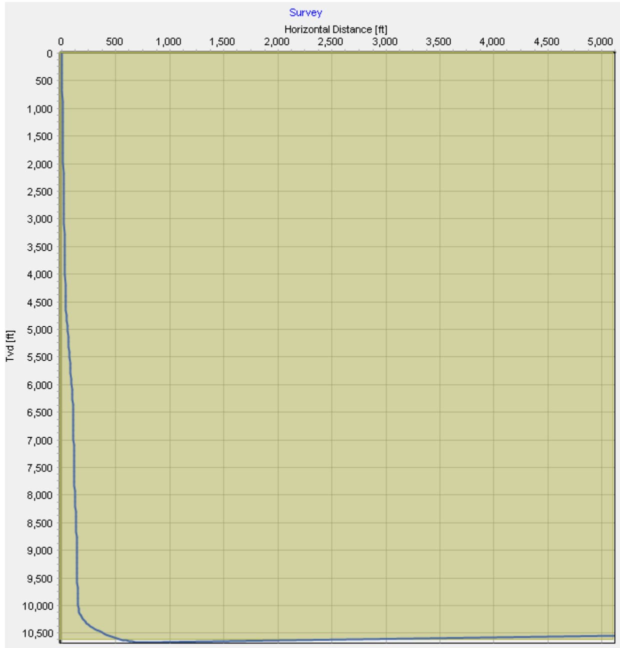


Figure 3.106. Case Study 2B7 Well Survey

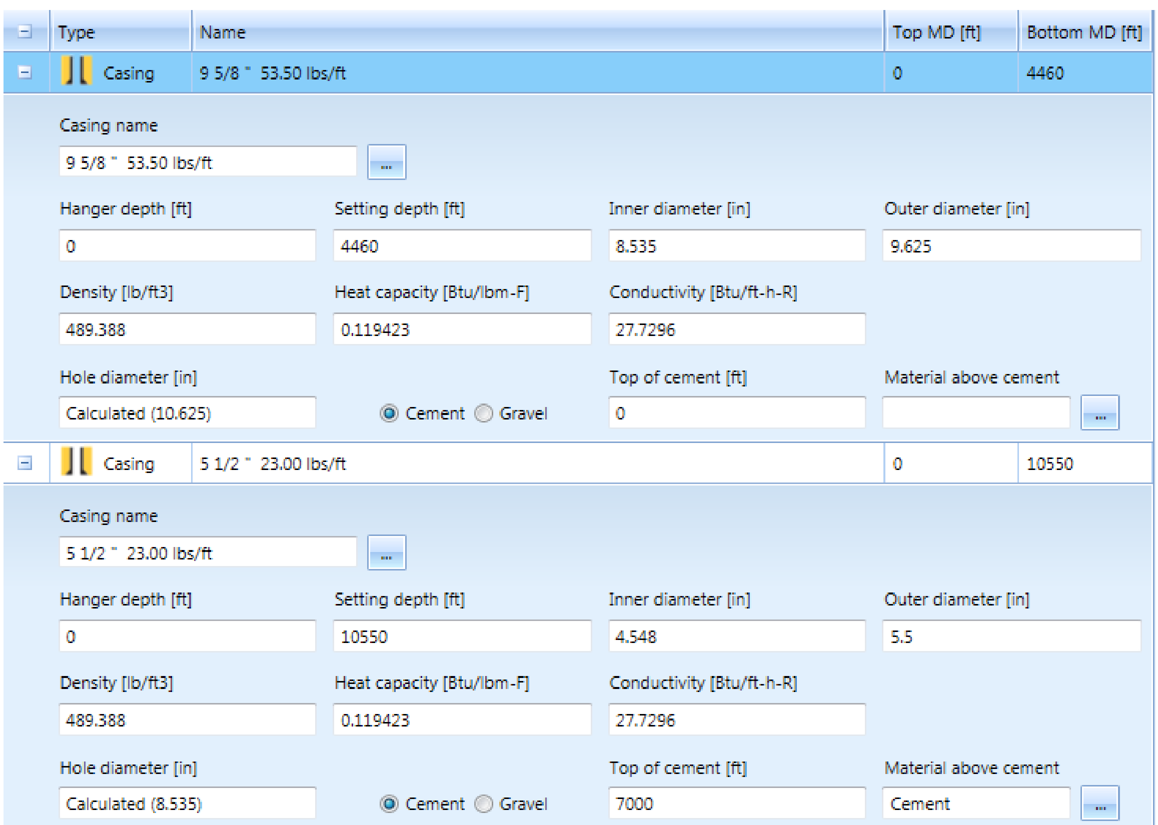


Figure 3.107. Case Study 2B7 Completion Design In Detail

3.2.6.1. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.6.2. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.6.3. Unloading simulation conditions. It follows the same injection flow rate, temperature, pressure and time of injection which was applied to the Case Study 1A1.

3.2.6.4. Results. The following section will show the results for the unloading simulation starting with the hold-up in the tubing, annulus and lateral section of the Case Study 2B7.

3.2.6.5. Hold-Up. Figure 3.108 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process starts.

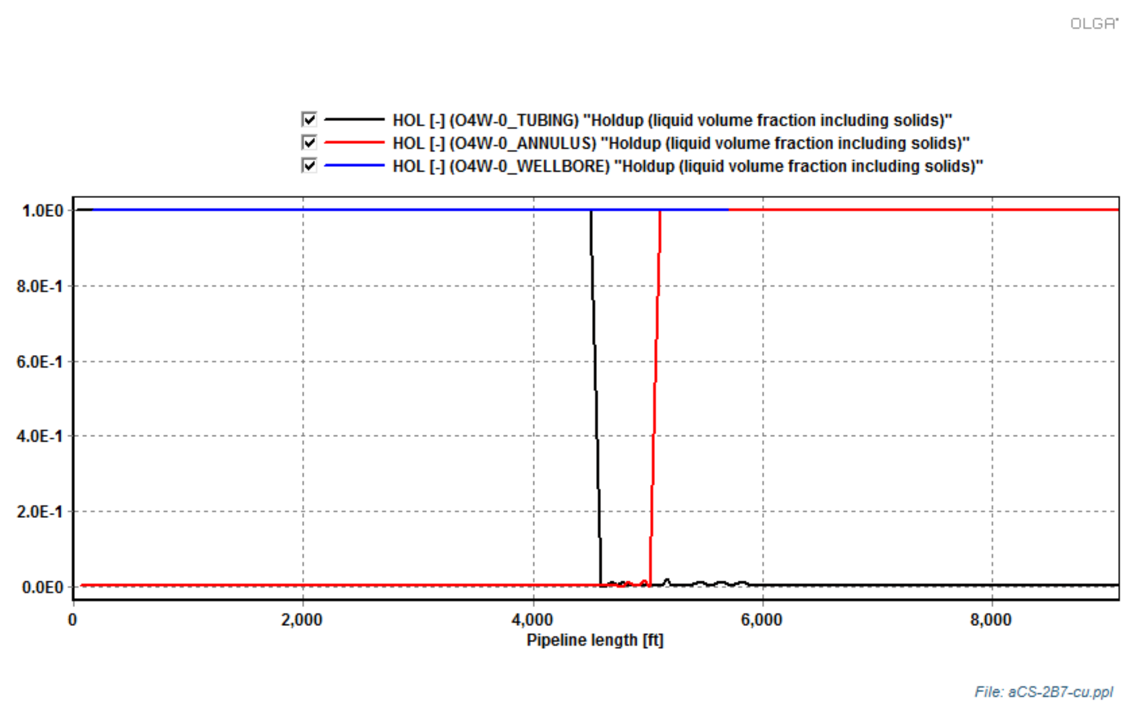


Figure 3.108. Hold-Up At Time=0min Of Unloading Process Profile Plot Case Study 2B7

Figure 3.109 shows the hold-up for the tubing, annulus and lateral section in a 3D model.

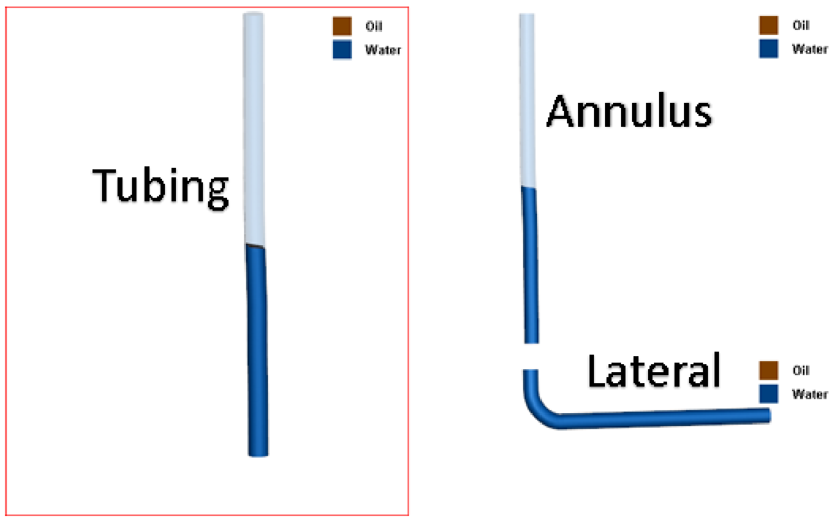


Figure 3.109. Hold-Up At Time=0min Of Unloading Process 3D Plot Case Study 2B7

Figure 3.110 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 10min.

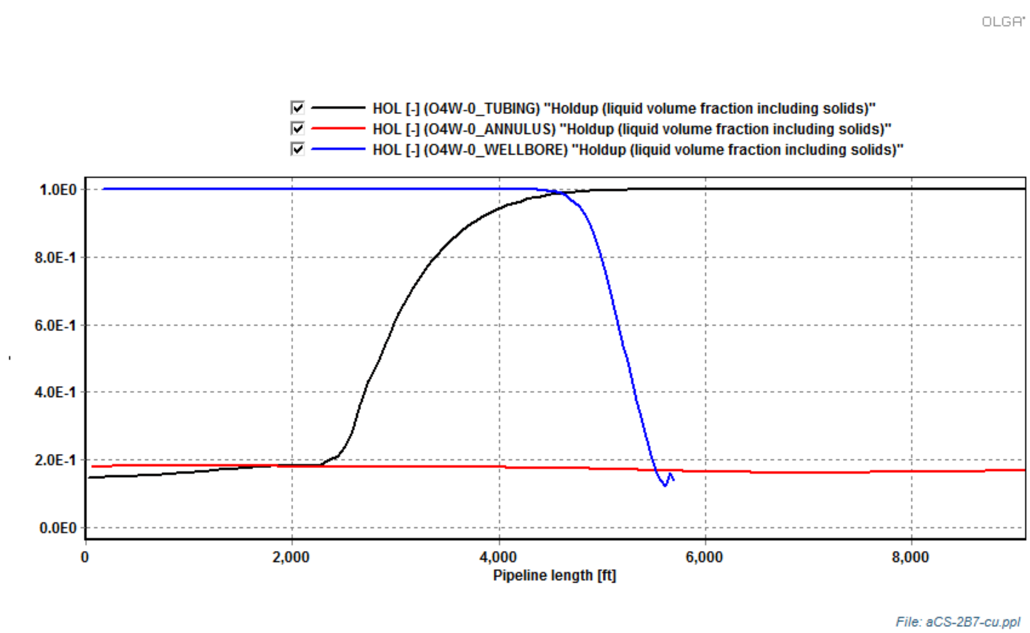


Figure 3.110. Hold-Up At Time=10min Of Unloading Process Profile Plot Case Study 2B7

Figure 3.111 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 10min of injection.

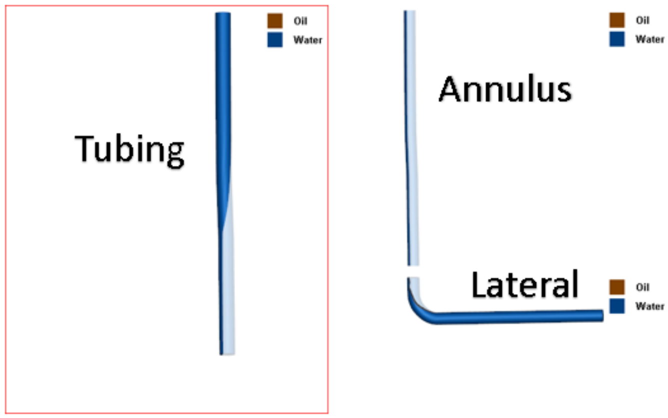


Figure 3.111. Hold-Up At Time=10min Of Unloading Process 3D Plot Case Study 2B7

Figure 3.112 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 20min.

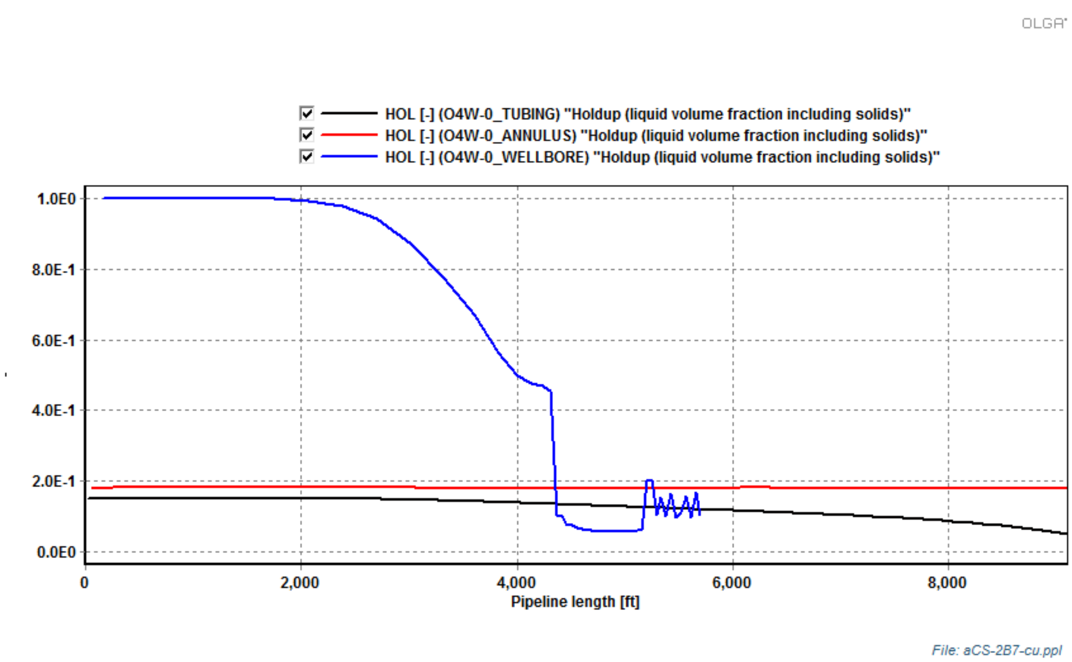


Figure 3.112. Hold-Up At Time=20min Of Unloading Process Profile Plot Case Study 2B7

Figure 3.113 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 20min of injection.

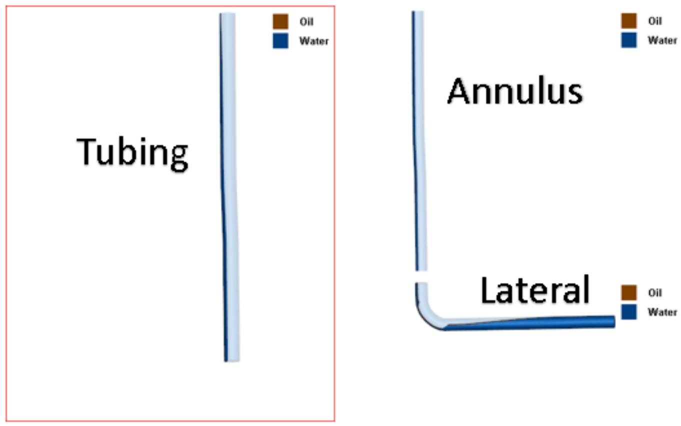


Figure 3.113. Hold-Up At Time=20min Of Unloading Process 3D Plot Case Study 2B7

Figure 3.114 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 40min.

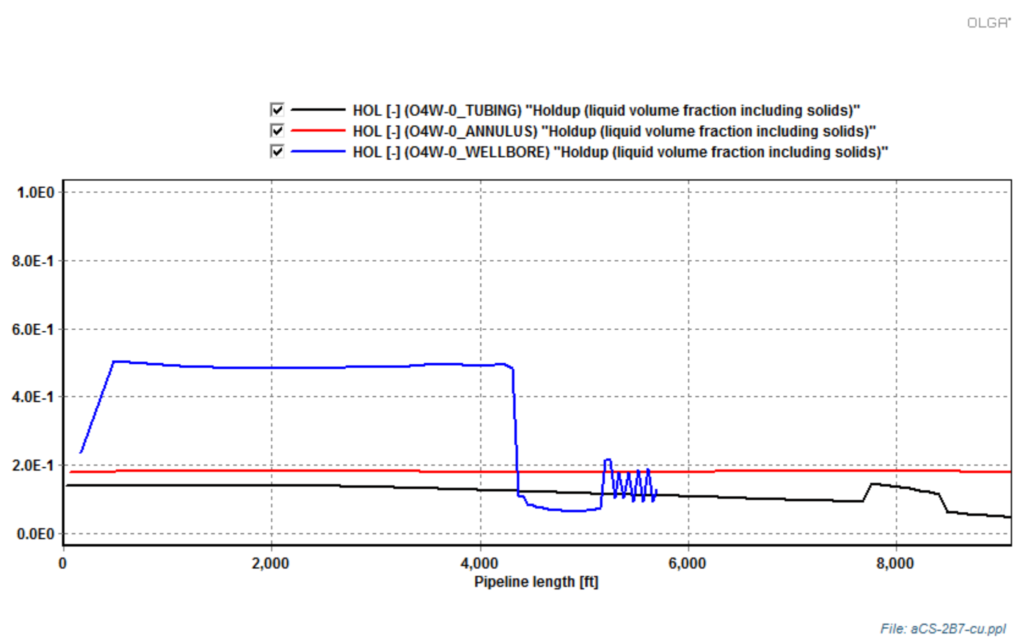


Figure 3.114. Hold-Up At Time=40min Of Unloading Process Profile Plot Case Study 2B7

Figure 3.115 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 40min of injection.

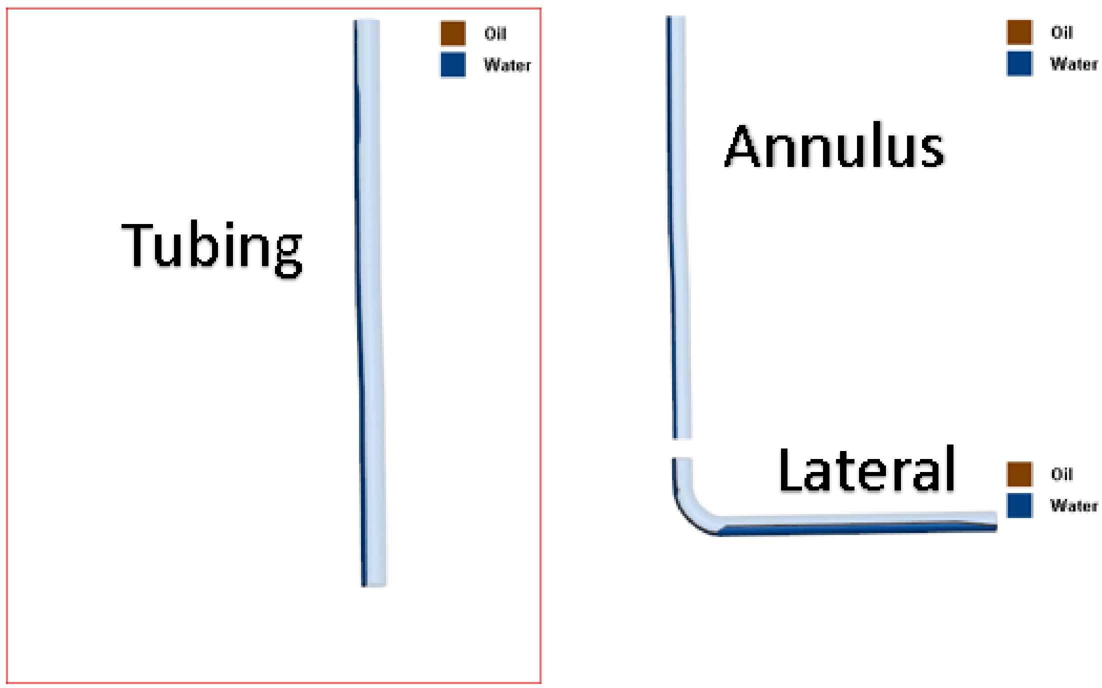


Figure 3.115. Hold-Up At Time=40min Of Unloading Process 3D Plot Case Study 2B7

After this time, the nitrogen injection stops allowing the reservoir to produce gas naturally.

3.2.6.6. Temperature and pressure. In this section, the temperature and pressure are plotted for Case Study 2B7.

Figure 3.116 details the pressure and temperature at the tubing, annulus and lateral section of the wellbore when the unloading process starts.

Figure 3.117 shows the same parameters after 10min of injection. Figure 3.118 shows the same parameters after 40min of injection.

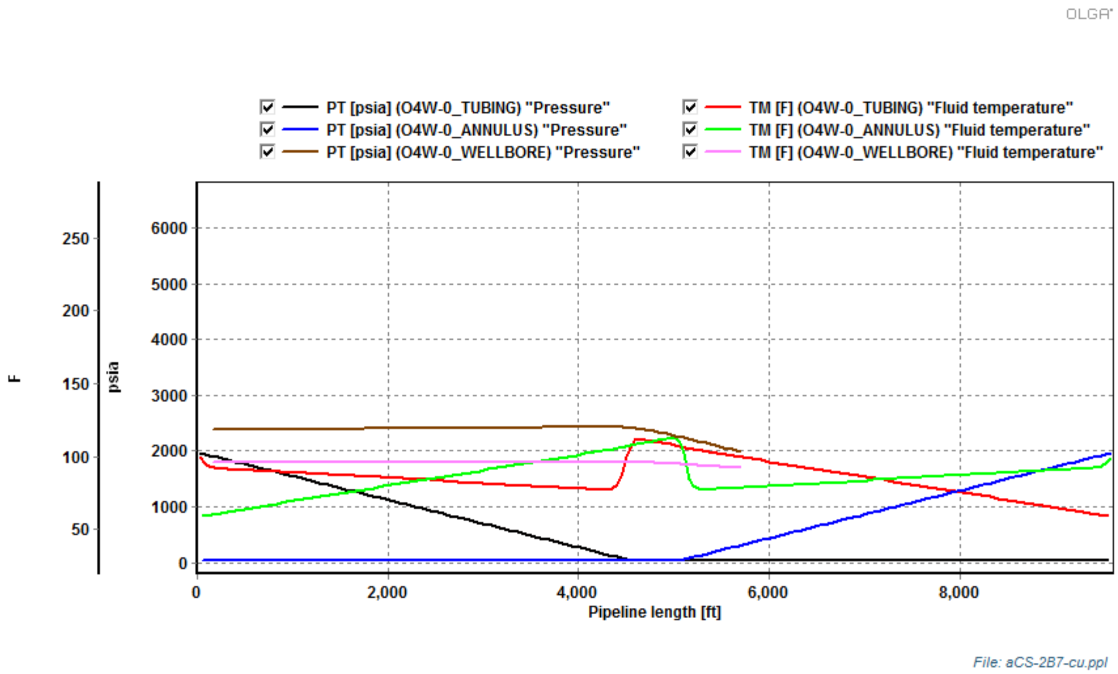


Figure 3.116. Temperature And Pressure At Time=0min Of Unloading Process Profile Plot Case Study 2B7

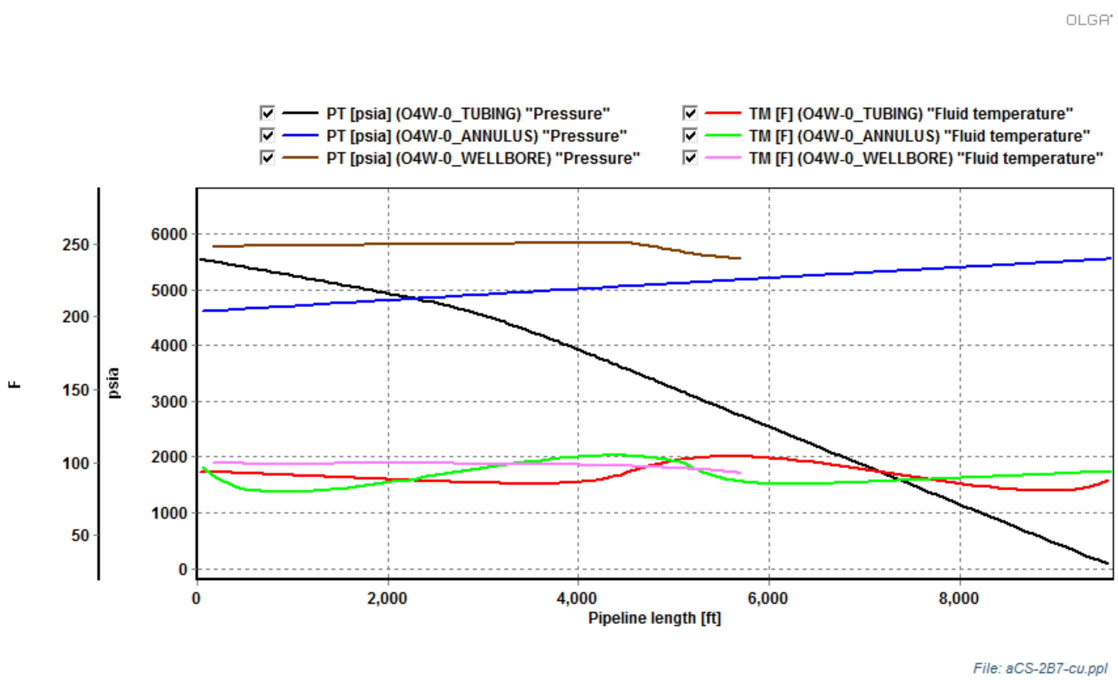


Figure 3.117. Temperature And Pressure At Time=10min Of Unloading Process Profile Plot Case Study 2B7

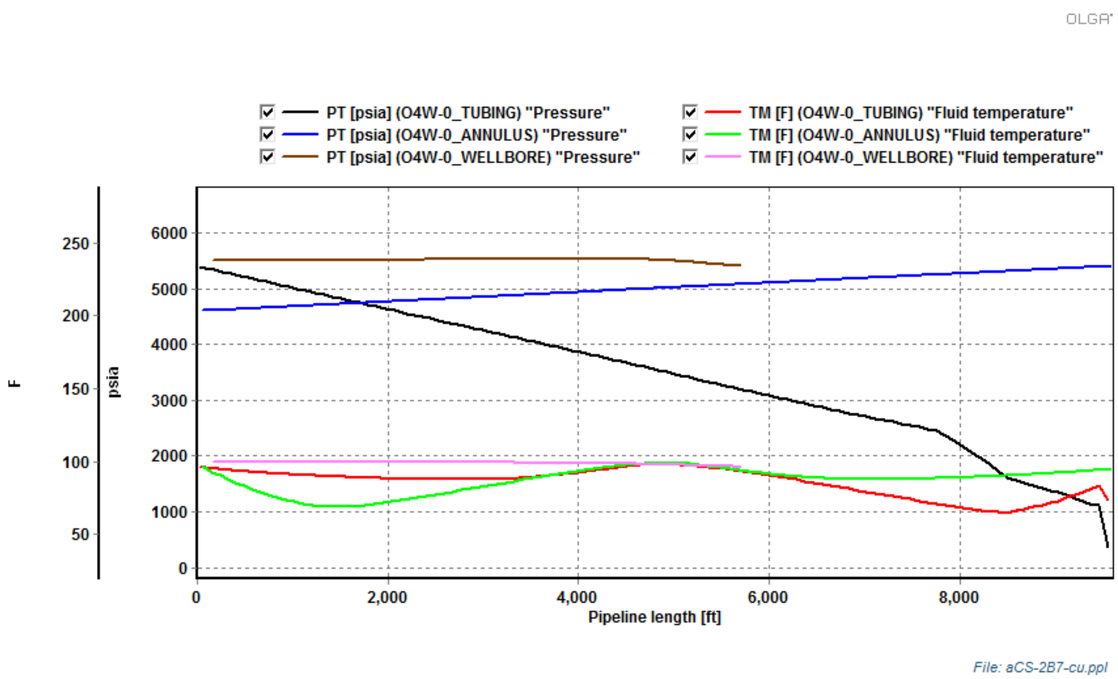


Figure 3.118. Temperature And Pressure At Time=40min Of Unloading Process Profile Plot Case Study 2B7

3.2.7. Case Study 2B8 (Slick-Water + Friction Reducer MP20A02 Plastic Viscosity 3.7cp). This Case Study describes the behavior of the nitrogen for unloading in a gas well that was loaded by slickwater + friction reducer MP20A02 as a frac fluid with a plastic viscosity of 3.7cP.

3.2.7.1. Survey. Figure 3.119 describes the survey for a horizontal well trajectory. The gas well survey is taken from Case Study 1A1.

3.2.7.2. Completion design. The completion design is the same as for the base case as shown in Figure 3.120.

The tubing remains the same as the Case Study 1A1. It reaches 9,606 ft from the surface.

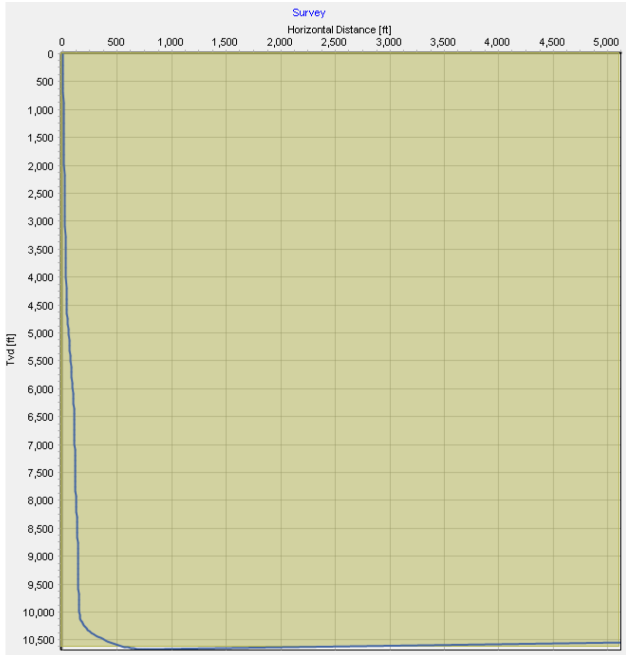


Figure 3.119. Case Study 2B8 Well Survey

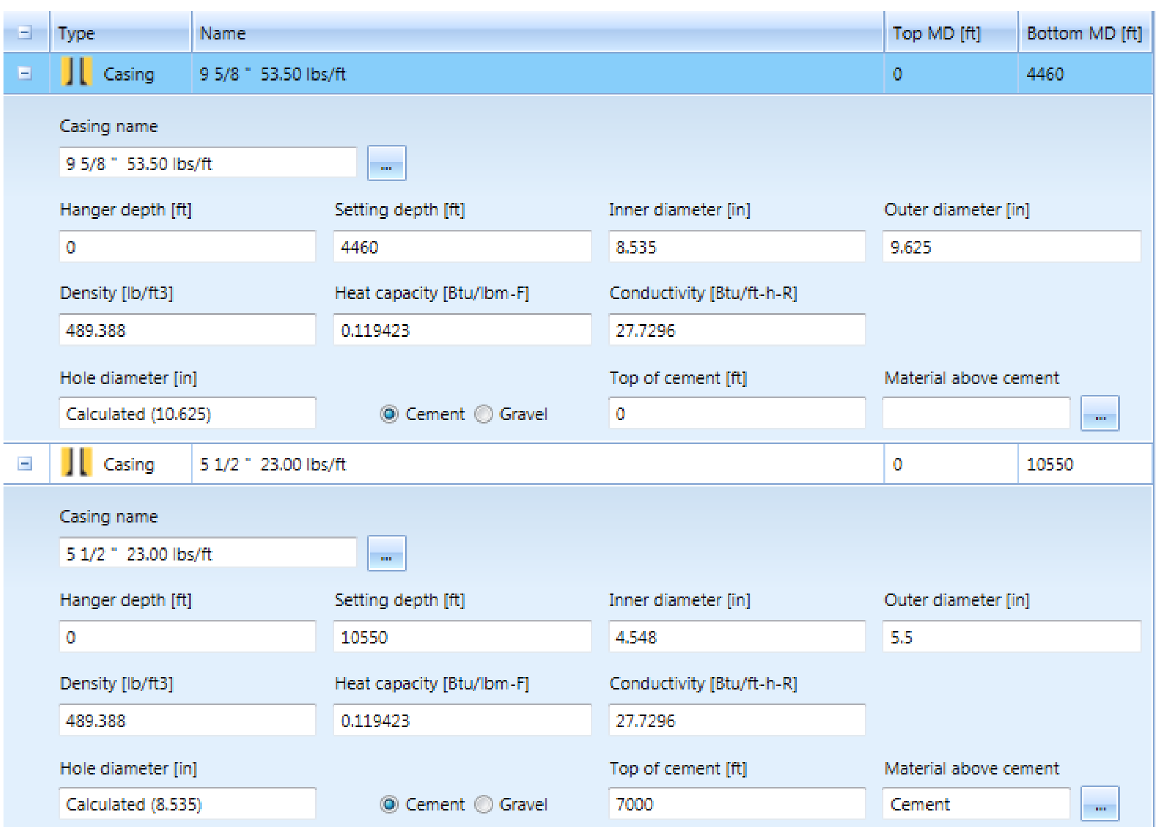


Figure 3.120. Case Study 2B8 Completion Design In Detail

3.2.7.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.7.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.7.5. Unloading simulation conditions. It follows the same injection flow rate, temperature, pressure and time of injection which was applied to the Case Study 1A1.

3.2.7.6. Results. The following section will show the results for the unloading simulation starting with the hold-up in the tubing, annulus and lateral section of the Case Study 2B8.

3.2.7.7. Hold-Up. Figure 3.121 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process starts.

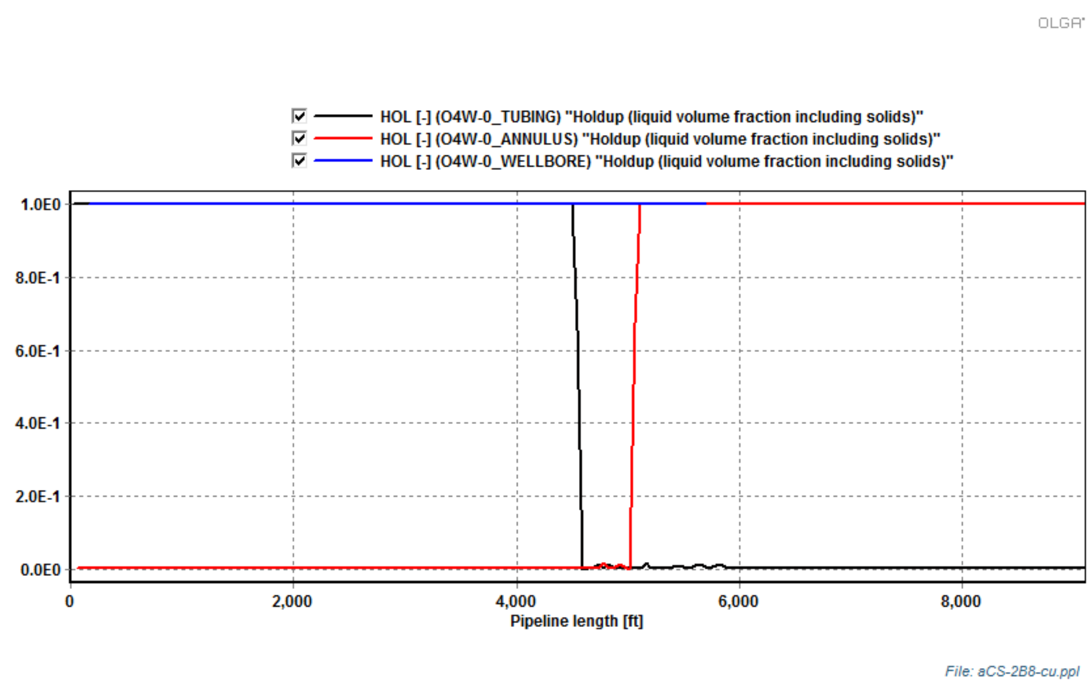


Figure 3.121. Hold-Up At Time=0min Of Unloading Process Profile Plot Case Study 2B8

Figure 3.122 shows the hold-up for the tubing, annulus and lateral section in a 3D model.

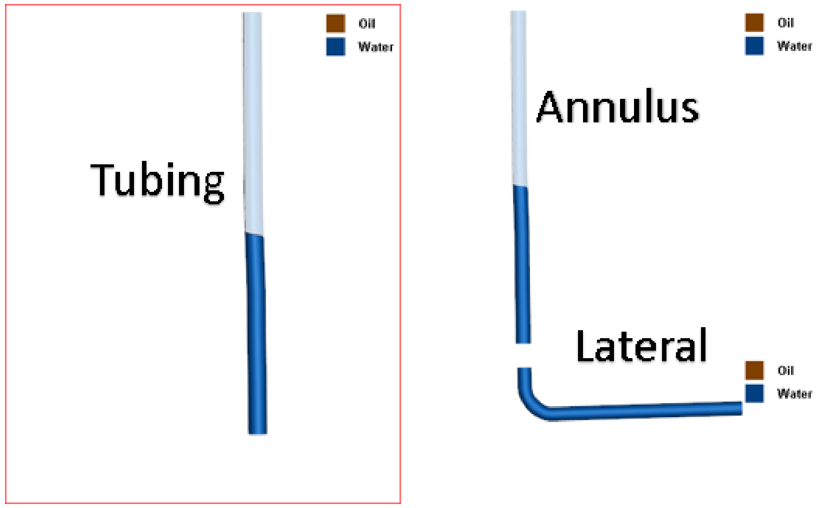


Figure 3.122. Hold-Up At Time=0min Of Unloading Process 3D Plot Case Study 2B8

Figure 3.123 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 10min.

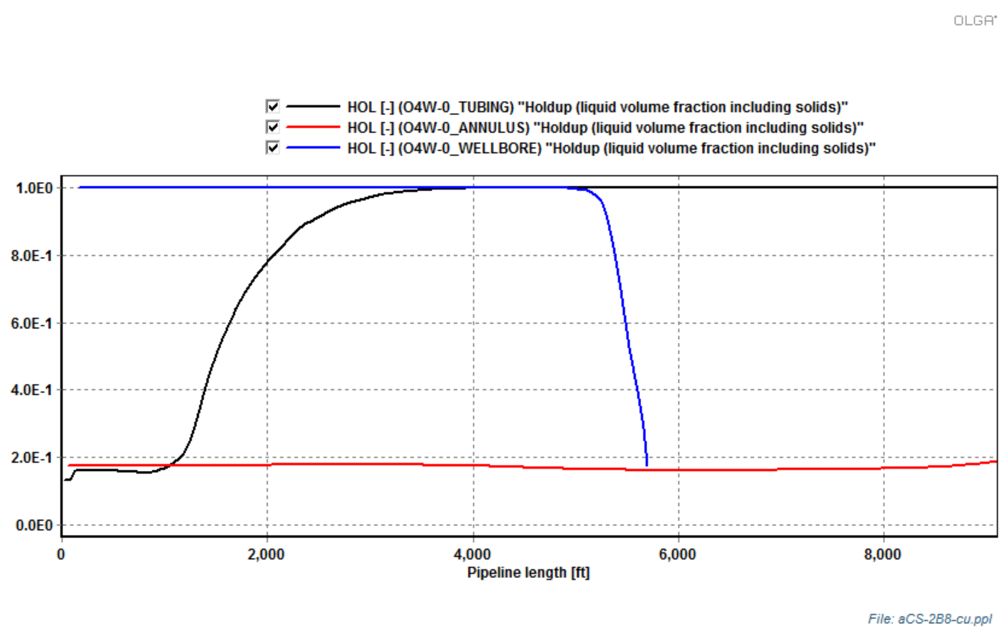


Figure 3.123. Hold-Up At Time=10min Of Unloading Process Profile Plot Case Study 2B8

Figure 3.124 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 10min of injection.

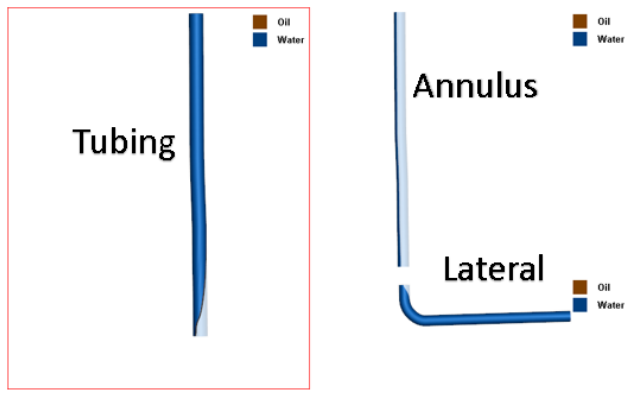


Figure 3.124.. Hold-Up At Time=10min Of Unloading Process 3D Plot Case Study 2B8

Figure 3.125 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 20min.

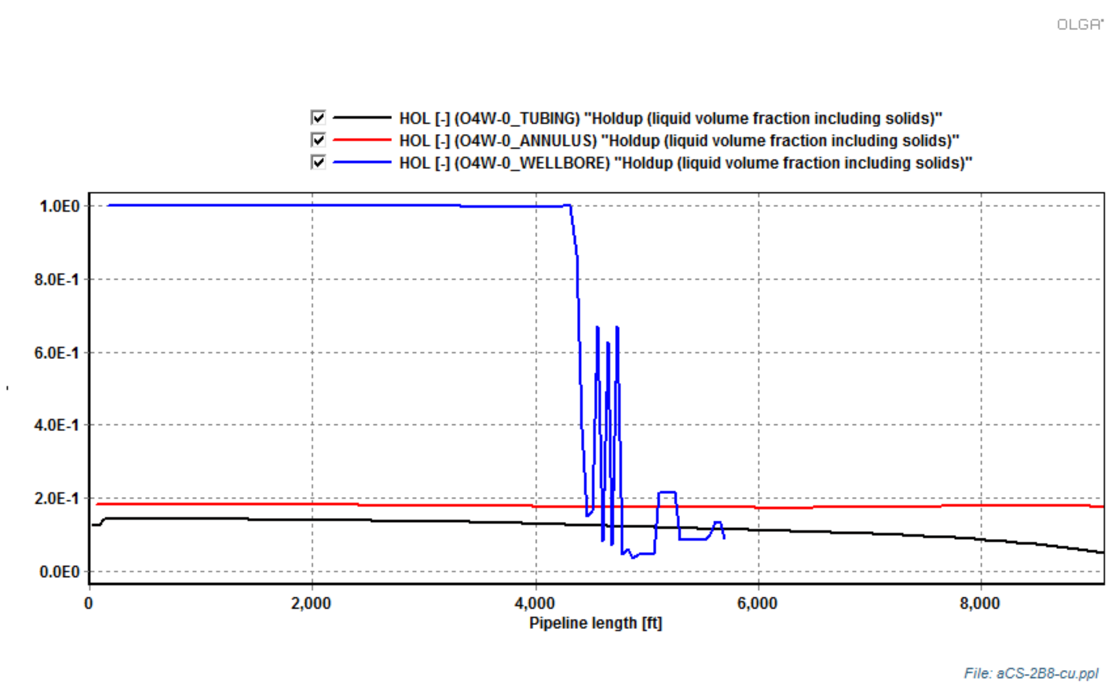


Figure 3.125 Hold-Up At Time=20min Of Unloading Process Profile Plot Case Study 2B8

Figure 3.126 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 20min of injection.

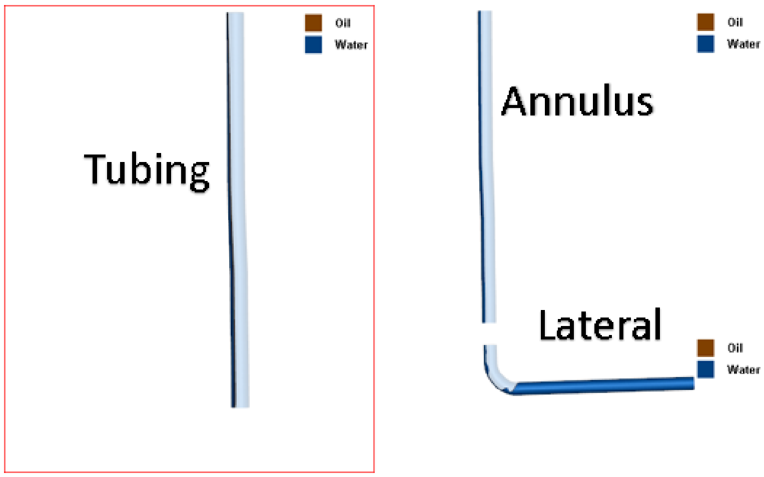


Figure 3.126. Hold-Up At Time=20min Of Unloading Process 3D Plot Case Study 2B8

Figure 3.127 shows the hold-up for the tubing, annulus and lateral section of the well when the unloading process reaches 40min.

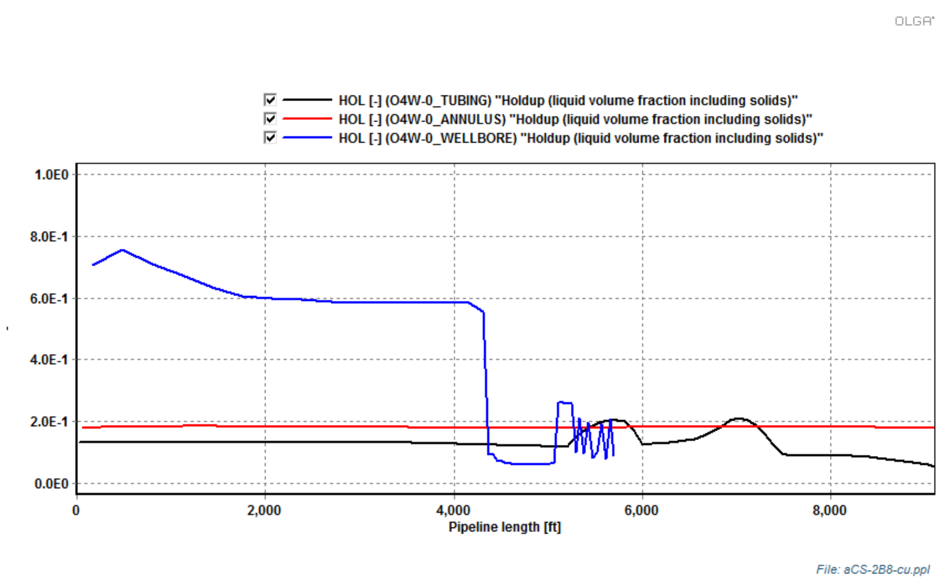


Figure 3.127. Hold-Up At Time=40min Of Unloading Process Profile Plot Case Study 2B8

Figure 3.128 shows the hold-up for the tubing, annulus and lateral section in a 3D model when the unloading process is at 40min of injection.

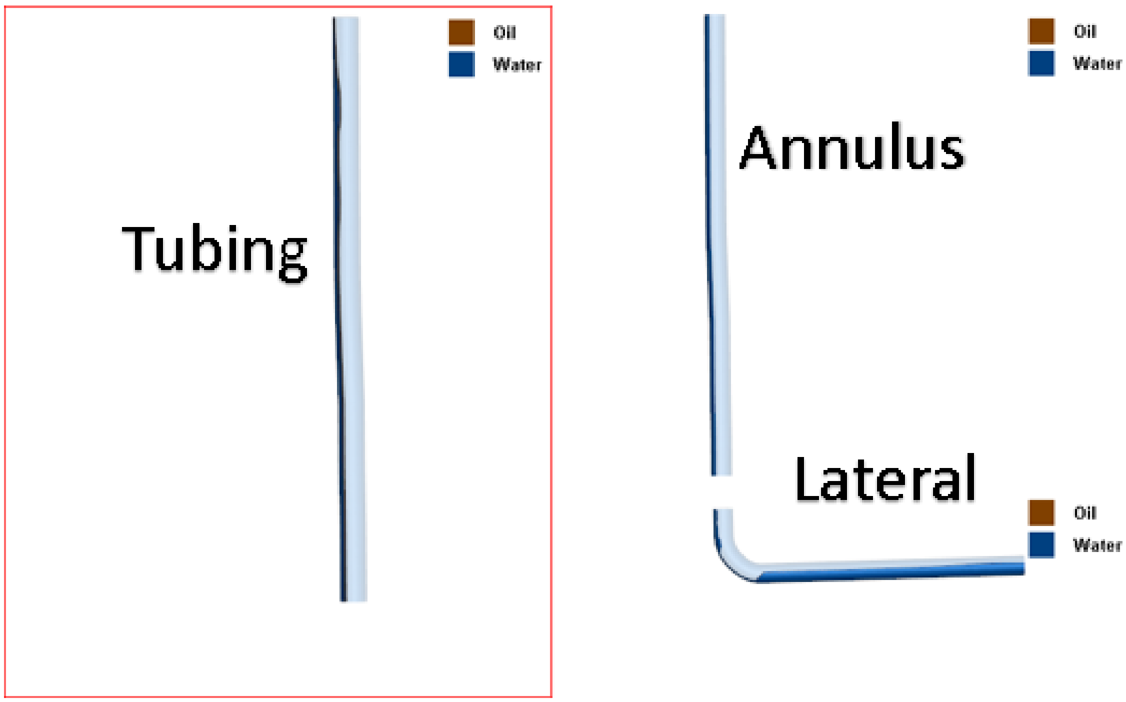


Figure 3.128. Hold-Up At Time=40min Of Unloading Process 3D Plot Case Study 2B8

After this time, the nitrogen injection stops allowing the reservoir to produce gas naturally.

3.2.7.8. Temperature and pressure. In this section, the temperature and pressure are plotted for Case Study 2B8.

Figure 3.129 details the pressure and temperature at the tubing, annulus and lateral section of the wellbore when the unloading process starts.

Figure 3.130 shows the same parameters after 10min of injection. Figure 3.131 shows the same parameters after 40min of injection.

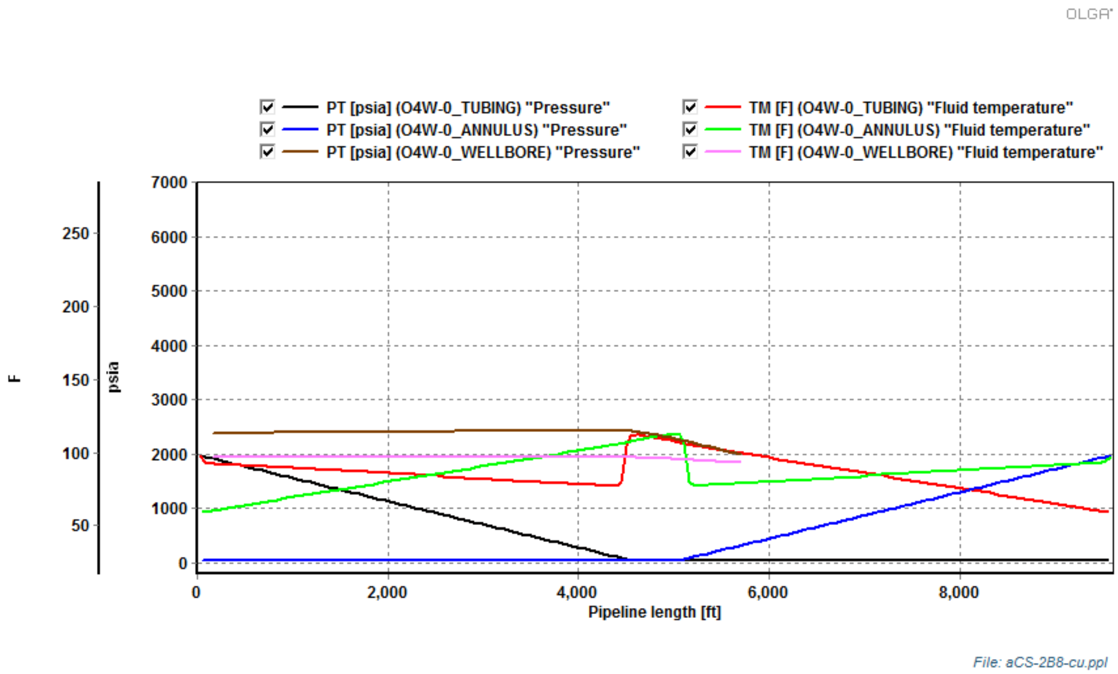


Figure 3.129. Temperature And Pressure At Time=0min Of Unloading Process Profile Plot Case Study 2B8

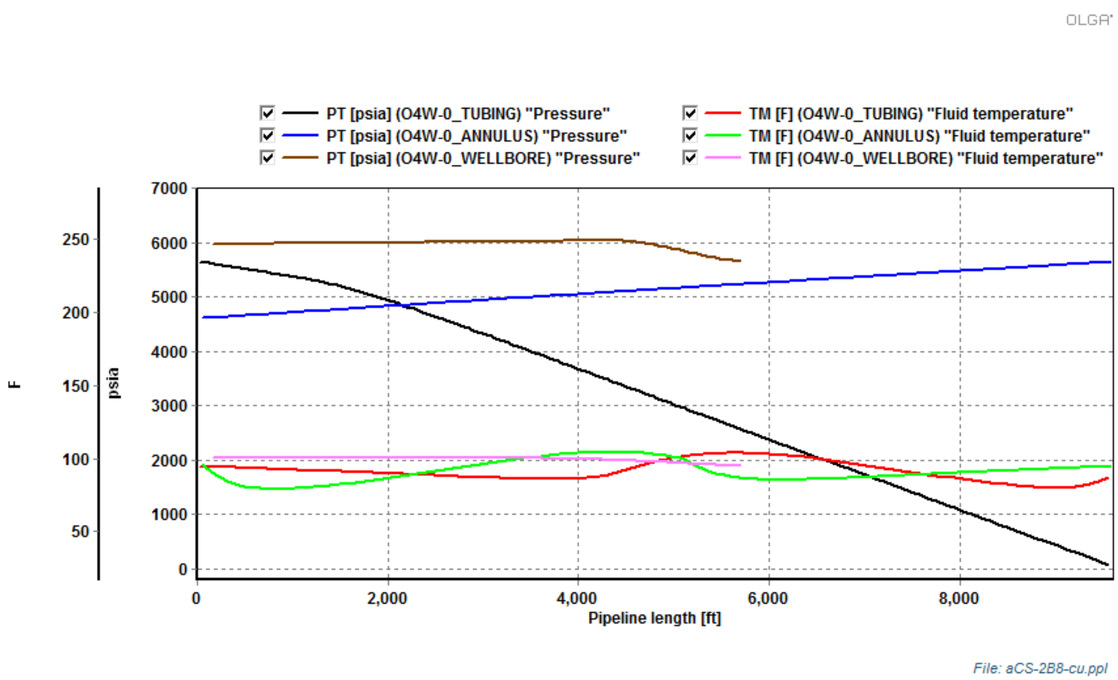


Figure 3.130. Temperature And Pressure At Time=10min Of Unloading Process Profile Plot Case Study 2B8

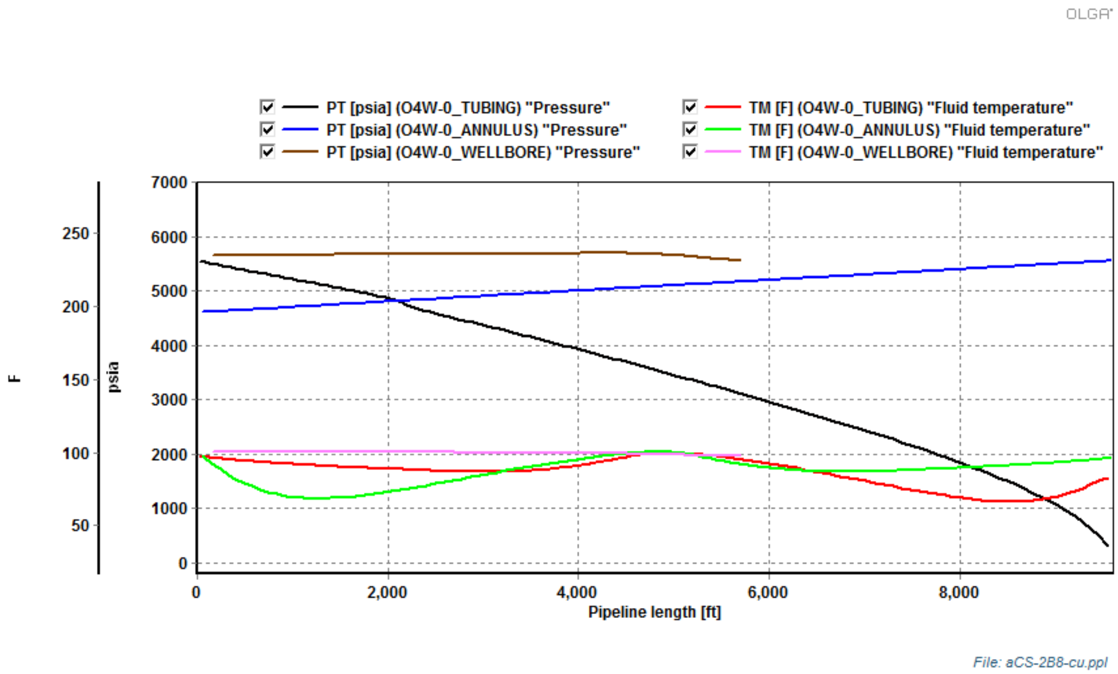


Figure 3.131. Temperature And Pressure At Time=40min Of Unloading Process Profile Plot Case Study 2B8

3.2.8. Case Study 2C14 (4400 Psia Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 4400psia from the surface.

3.2.8.1. Survey. It uses the same survey as Case Study 1A1.

3.2.8.2. Completion design. It is similar to Case Study 1A1.

3.2.8.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.8.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.8.5. Unloading simulation conditions. The temperature and mass rate of the nitrogen is the same as Case Study 1A1. However, the injection pressure of the nitrogen is in this case 4400 psia.

3.2.8.6. Results. This section will be shown in the following section.

3.2.9. Case Study 2C15 (4600 Psia Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 4600psia from the surface.

3.2.9.1. Survey. It uses the same survey as Case Study 1A1.

3.2.9.2. Completion design. It is similar to Case Study 1A1.

3.2.9.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.9.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.9.5. Unloading simulation conditions. The temperature and mass rate of the nitrogen is the same as Case Study 1A1. However, the injection pressure of the nitrogen is in this case 4600 psia.

3.2.9.6. Results. This section will be shown in the following section.

3.2.10. Case Study 2C16 (4800 Psia Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 4800psia from the surface.

3.2.10.1. Survey. It uses the same survey as Case Study 1A1.

3.2.10.2. Completion design. It is similar to Case Study 1A1.

3.2.10.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157 in.

3.2.10.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.10.5. Unloading simulation conditions. The temperature and mass rate of the nitrogen is the same as Case Study 1A1. However, the injection pressure of the nitrogen is in this case 4800 psia.

3.2.10.6. Results. This section will be shown in the following section.

3.2.11. Case Study 2C17 (5000 Psia Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 5000psia from the surface.

3.2.11.1. Survey. It uses the same survey as Case Study 1A1.

3.2.11.2. Completion Design. It is similar to Case Study 1A1.

3.2.11.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.11.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.11.5. Unloading simulation conditions. The temperature and mass rate of the nitrogen is the same as Case Study 1A1. However, the injection pressure of the nitrogen is in this case 5000 psia.

3.2.11.6. Results. This section will be shown in the following section.

3.2.12. Case Study 2C18 (5200 Psia Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 5200psia from the surface.

3.2.12.1. Survey. It uses the same survey as Case Study 1A1.

3.2.12.2. Completion design. It is similar to Case Study 1A1.

3.2.12.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.12.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.12.5. Unloading simulation conditions. The temperature and mass rate of the nitrogen is the same as Case Study 1A1.

However, the injection pressure of the nitrogen is in this case 5200 psia.

3.2.12.6. Results. This section will be shown in the following section.

3.2.13. Case Study 2C19 (1.0 Lb/S Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 1.0 lb/s from the surface.

3.2.13.1. Survey. It uses the same survey as Case Study 1A1.

3.2.13.2. Completion design. It is similar to Case Study 1A1.

3.2.13.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.13.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.13.5. Unloading simulation conditions. The temperature and injection fluid pressure are the same as Case Study 1A1. However, the mass rate of the nitrogen is in this case 1.0 lb/s.

3.2.13.6. Results. This section will be shown in the following section.

3.2.14. Case Study 2C20 (1.1 Lb/S Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 1.1 lb/s from the surface.

3.2.14.1. Survey. It uses the same survey as Case Study 1A1.

3.2.14.2. Completion design. It is similar to Case Study 1A1.

3.2.14.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157 in.

3.2.14.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.14.5. Unloading simulation conditions. The temperature and injection fluid pressure are the same as Case Study 1A1. However, the mass rate of the nitrogen is in this case 1.1 lb/s.

3.2.14.6. Results. This section will be shown in the following section.

3.2.15. Case Study 2C21 (1.2 Lb/S Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 1.2 lb/s from the surface.

3.2.15.1. Survey. It uses the same survey as Case Study 1A1.

3.2.15.2. Completion design. It is similar to Case Study 1A1.

3.2.15.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157 in.

3.2.15.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.15.5. Unloading simulation conditions. The temperature and injection fluid pressure are the same as Case Study 1A1. However, the mass rate of the nitrogen is in this case 1.2 lb/s.

3.2.15.6. Results. This section will be shown in the following section.

3.2.16. Case Study 2C22 (1.3 Lb/S Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 1.3 lb/s from the surface.

3.2.16.1. Survey. It uses the same survey as Case Study 1A1.

3.2.16.2. Completion design. It is similar to Case Study 1A1.

3.2.16.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.16.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.16.5. Unloading simulation conditions. The temperature and injection fluid pressure are the same as Case Study 1A1. However, the mass rate of the nitrogen is in this case 1.3 lb/s.

3.2.16.6. Results. This section will be shown in the following section.

3.2.17. Case Study 2C23 (1.4 Lb/S Nitrogen). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the nitrogen is injected at 1.4 lb/s from the surface.

3.2.17.1. Survey. It uses the same survey as Case Study 1A1.

3.2.17.2. Completion design. It is similar to Case Study 1A1.

3.2.17.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.17.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.17.5. Unloading simulation conditions. The temperature and injection fluid pressure are the same as Case Study 1A1. However, the mass rate of the nitrogen is in this case 1.4 lb/s.

3.2.17.6. Results. This section will be shown in the following section.

3.2.18. Case Study 2D24 (10120 Ft Tubing Depth). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the tubing reaches 10120 ft MD.

3.2.18.1. Survey. It uses the same survey as Case Study 1A1.

3.2.18.2. Completion design. It is similar to Case Study 1A1. However, the tubing reaches 514 ft deeper than Case Study 1A1.

3.2.18.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.18.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.18.5. Unloading simulation conditions. The temperature, the mass rate, and injection fluid pressure are the same as Case Study 1A1

3.2.18.6. Results. This section will be shown in the following section.

3.2.19. Case Study 2D25 (10920 Ft Tubing Depth). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the tubing reaches 10920 ft MD.

3.2.19.1. Survey. It uses the same survey as Case Study 1A1.

3.2.19.2. Completion design. It is similar to Case Study 1A1. However, the tubing reaches 1314 ft deeper than Case Study 1A1.

3.2.19.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.2.19.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.2.19.5. Unloading simulation conditions. The temperature, the mass rate, and injection fluid pressure are the same as Case Study 1A1

3.2.19.6. Results. Results will be discussed in the following section.

3.3. VOLUME TO BE DISPLACED

Volume to be displaced represents the total frac fluid volume that is inside the gas well. Figure 3.132 illustrates the variables needed to calculate the volume to be displaced (VTBD).

It is calculated using the following formula:

$$\text{Volume to be displaced} = \text{Volume 1} + \text{Volume 2} \tag{10}$$

$$\text{Volume 1} = \pi * \left(MD_{Tubing} - MD_{Frac\ Fluid\ Liquid\ Level}\right) * \left(\frac{ID_{Casing}}{2}\right)^2 - \pi * \left(MD_{Tubing} - MD_{Frac\ Fluid\ Liquid\ Level}\right) * \left[\left(\frac{OD_{Tubing}}{2}\right)^2 - \left(\frac{ID_{Tubing}}{2}\right)^2\right] \quad (11)$$

$$\text{Volume 2} = \pi * \left(MD_{Casing} - MD_{Tubing}\right) * \left(\frac{ID_{Casing}}{2}\right)^2 \quad (12)$$

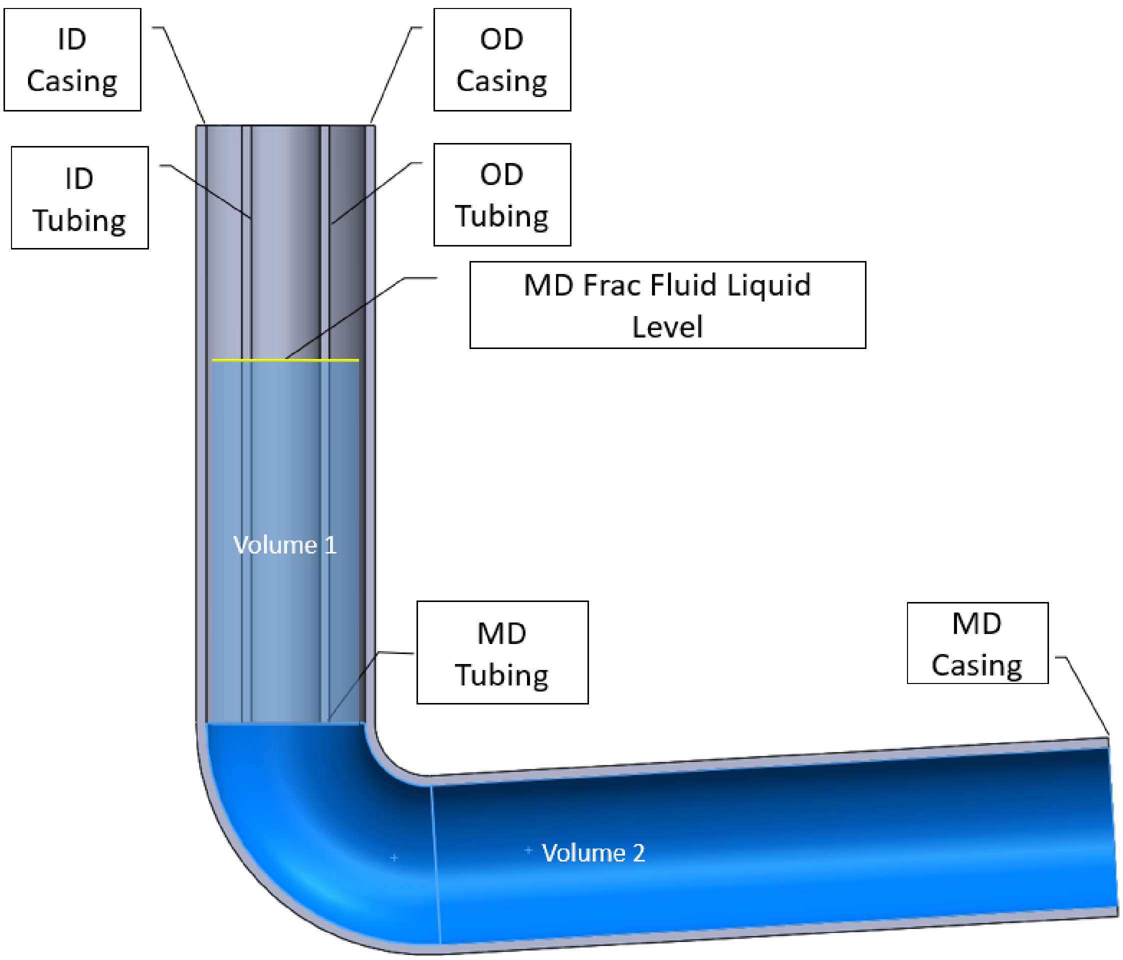


Figure 3.132. Volume To Be Displaced

3.4. TIME TO UNLOAD

Time to unload is defined as the time when the gas reservoir starts producing by its own after injecting nitrogen to reduce the hold-up inside the tubing.

Figure 3.133 shows that the time to unload is counted until the well is cleaned up and the reservoir starts to produce gas by its own.

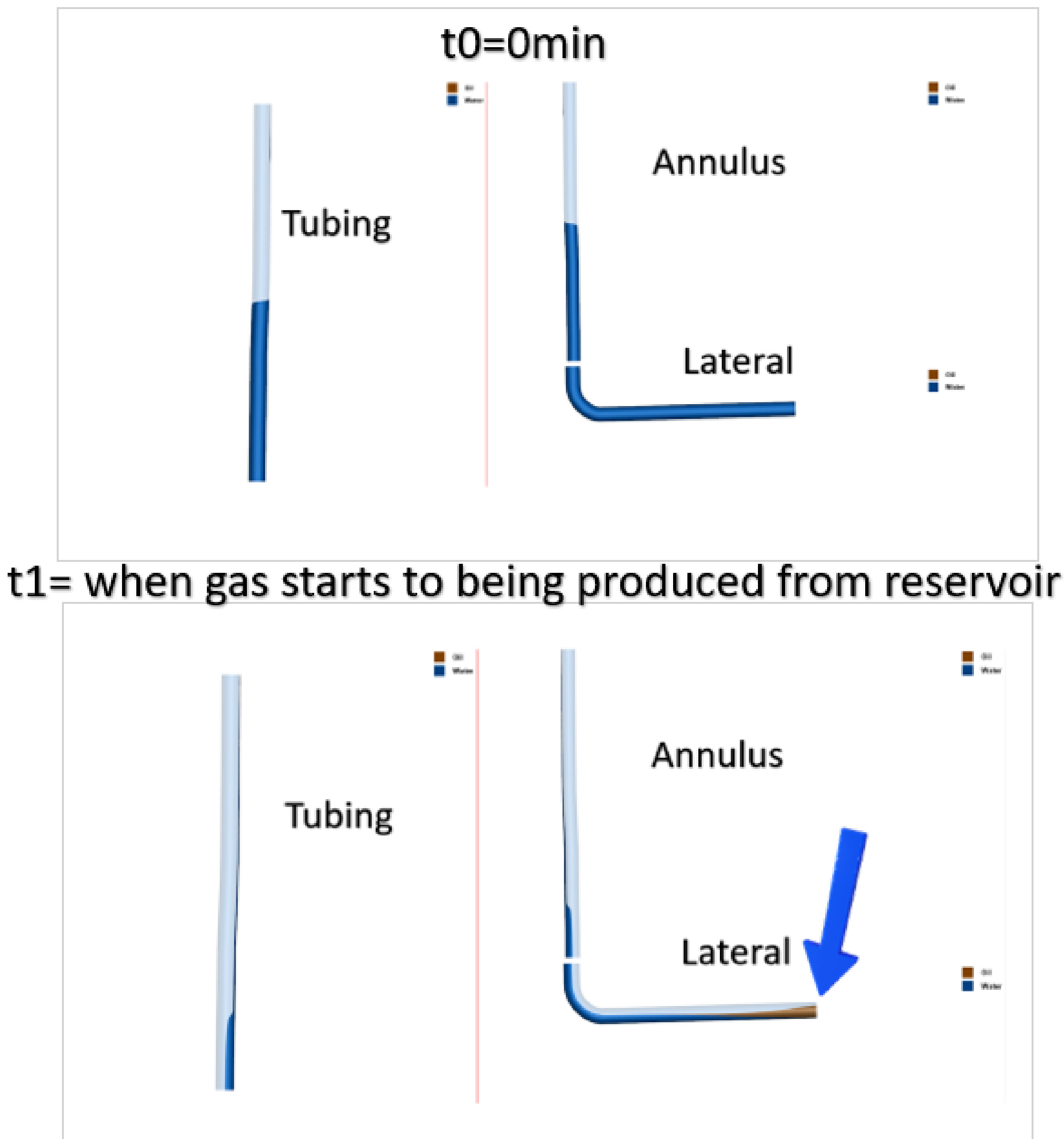


Figure 3.133. Time To Unload

3.5. PARAMETRIC STUDIES VARYING CASING AND TUBING SIZE

The following section studies the behavior of nitrogen when the casing and tubing size change.

3.5.1. Case Study Bcs-1A1. Refer to Appendix B for details, Section 1.

3.5.2. Case Study Bcs-1A2. Refer to Appendix B for details, Section 2.

3.5.3. Case Study Bcs-1A3. Refer to Appendix B for details, Section 3.

3.5.4. Case Study Bcs-1A4. Refer to Appendix B for details, Section 4.

3.5.5. Case Study Bcs-1A5. Refer to Appendix B for details, Section 5.

3.5.6. Case Study Bcs-1A6. Refer to Appendix B for details, Section 6.

3.5.7. Case Study Bcs-1A7. Refer to Appendix B for details, Section 7.

3.5.8. Case Study Bcs-1A8. Refer to Appendix B for details, Section 8.

3.5.9. Case Study Bcs-1A9. Refer to Appendix B for details, Section 9.

3.5.10. Case Study Bcs-1A10. Refer to Appendix B for details, Section 10.

3.5.11. Case Study Bcs-1A11. Refer to Appendix B for details, Section 11.

3.5.12. Case Study Bcs-1A12. Refer to Appendix B for details, Section 12.

3.5.13. Case Study Bcs-1A13. Refer to Appendix B for details, Section 13.

3.5.14. Case Study Bcs-1A14. Refer to Appendix B for details, Section 14.

3.5.15. Case Study Bcs-1A15. Refer to Appendix B for details, Section 15.

3.5.16. Case Study Bcs-1A16. Refer to Appendix B for details, Section 16.

3.5.17. Case Study Bcs-1A17. Refer to Appendix B for details, Section 17.

3.5.18. Case Study Bcs-1A18. Refer to Appendix B for details, Section 18.

3.5.19. Case Study Bcs-1A19. Refer to Appendix B for details, Section 19.

3.5.20. Case Study Bcs-1A20. Refer to Appendix B for details, Section 20.

3.5.21. Case Study Bcs-1A21. Refer to Appendix B for details, Section 21.

3.5.22. Case Study Bcs-1A22. Refer to Appendix B for details, Section 22.

3.5.23. Case Study Bcs-1A23. Refer to Appendix B for details, Section 23.

3.5.24. Case Study Bcs-1A24. Refer to Appendix B for details, Section 24.

3.6. INJECTING METHANE INSTEAD OF NITROGEN

The following section studies the behavior of methane as an alternative of nitrogen to unload gas wells.

3.6.1. Case Study 2E25 (9606 ft Tubing Depth Methane). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the tubing reaches 9606 ft MD.

3.6.1.1. Survey. It uses the same survey as Case Study 1A1.

3.6.1.2. Completion design. It is similar to Case Study 1A1. However, the tubing reaches 1314 ft deeper than Case Study 1A1.

3.6.1.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.6.1.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.6.1.5. Unloading simulation conditions. The temperature, the mass rate, and injection fluid pressure are the same as Case Study 1A1. However, it uses methane instead of nitrogen. Methane's density is 0.656 kg/m3.

3.6.1.6. Results. This section will be shown in the following section.

3.6.2. Case Study 2E26 (10120 ft Tubing Depth Methane). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the tubing reaches 10120 ft MD.

3.6.2.1. Survey. It uses the same survey as Case Study 1A1.

3.6.2.2. Completion design. It is similar to Case Study 1A1. However, the tubing reaches 1314 ft deeper than Case Study 1A1.

3.6.2.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.6.2.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.6.2.5. Unloading simulation conditions. The temperature, the mass rate, and injection fluid pressure are the same as Case Study 1A1. However, it uses methane instead of nitrogen. Methane's density is 0.656 kg/m3.

3.6.2.6. Results. This section will be shown in the following section.

3.6.3. Case Study 2E27 (10920 ft Tubing Depth Methane). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the tubing reaches 10920 ft MD.

3.6.3.1. Survey. It uses the same survey as Case Study 1A1.

3.6.3.2. Completion design. It is similar to Case Study 1A1. However, the tubing reaches 1314 ft deeper than Case Study 1A1.

3.6.3.3. Equipment. Comparably to Case 1A1, one valve is located in the tubing at the wellhead. The valve has an inner diameter of 2.157in.

3.6.3.4. Initial conditions. The same configuration as Case 1A1 is applied including the fluid level at initial conditions, temperature, and pressure.

3.6.3.5. Unloading simulation conditions. The temperature, the mass rate, and injection fluid pressure are the same as Case Study 1A1. However, it uses methane instead of nitrogen. Methane's density is 0.656 kg/m3.

3.6.3.6. Results. This section will be shown in the following section.

3.7. PARAMETRIC STUDIES VARYING LATERAL SECTION ANGLE

The following section studies the behavior of nitrogen when the lateral section changes its angle.

3.7.1. Case Study C1A1 (Toe Down). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the lateral section is located at 88.33 deg from the horizontal. Figure 3.134 illustrates the well survey.

3.7.2. Case Study C1A1 (Horizontal Toe). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the lateral section is located at 0 deg from the horizontal, in other words 90deg (completely horizontal). Figure 3.135 illustrates the well survey.

3.7.3. Case Study C1A1 (Toe Up). This Case Study describes the behavior of the nitrogen for unloading in a gas well when the lateral section is located at 91.67 deg from the horizontal. Figure 3.136 illustrates the well survey.

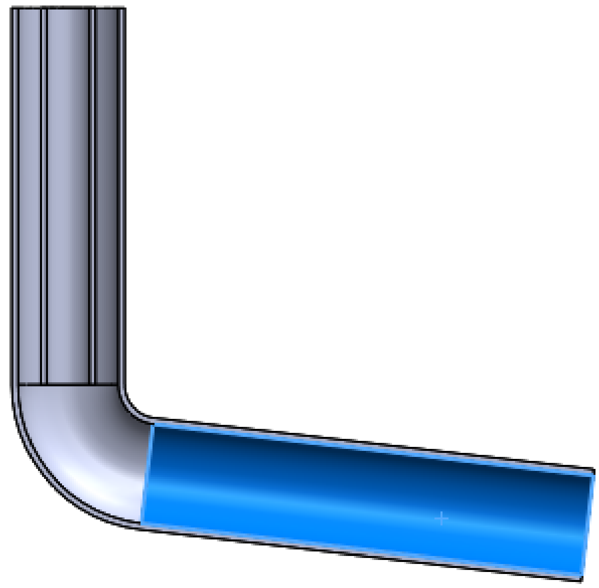


Figure 3.134. Lateral Section Toe Down

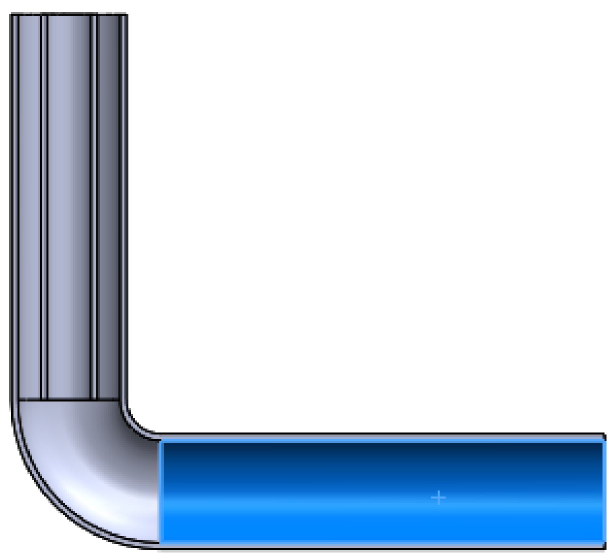


Figure 3.135. Lateral Section Horizontal Toe

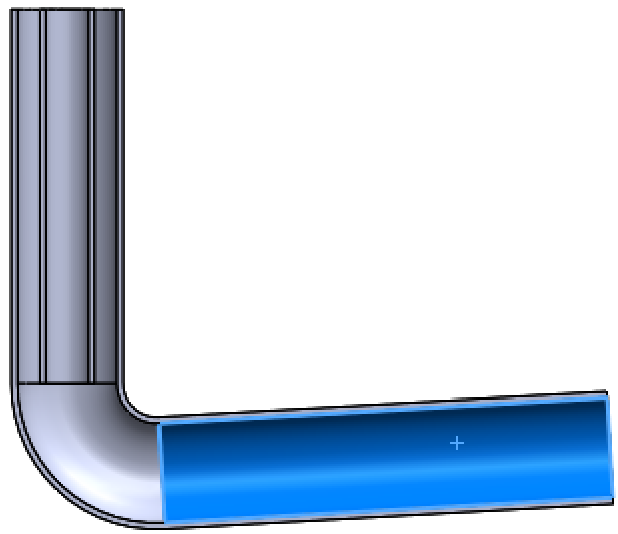


Figure 3.136. Lateral Section Toe Up

4. RESULTS

This section presents results of the parametric cases described in the previous chapter. It groups the results according to the change of injection fluid pressure, injection fluid mass rate, tubing depth, and frac fluid plastic viscosity.

4.1. VARIATION OF NITROGEN INJECTION PRESSURE

4.1.1. Pressure. Figure 4.1 shows the pressure for the annulus of the well when the unloading process starts. Figure 4.2 illustrates the behavior of nitrogen for different values of pressure after 60min (time of unloading). Figure 4.3 shows the pressure profile for all cases after the nitrogen stops being injected.

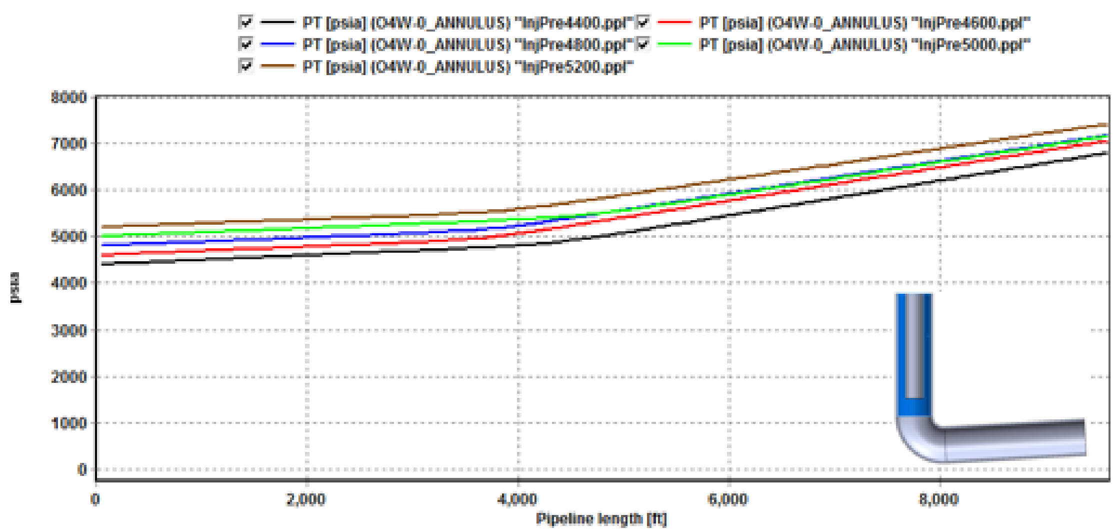


Figure 4.1. Pressure At Time=0min Of Annulus Due To Nitrogen Pressure Variation

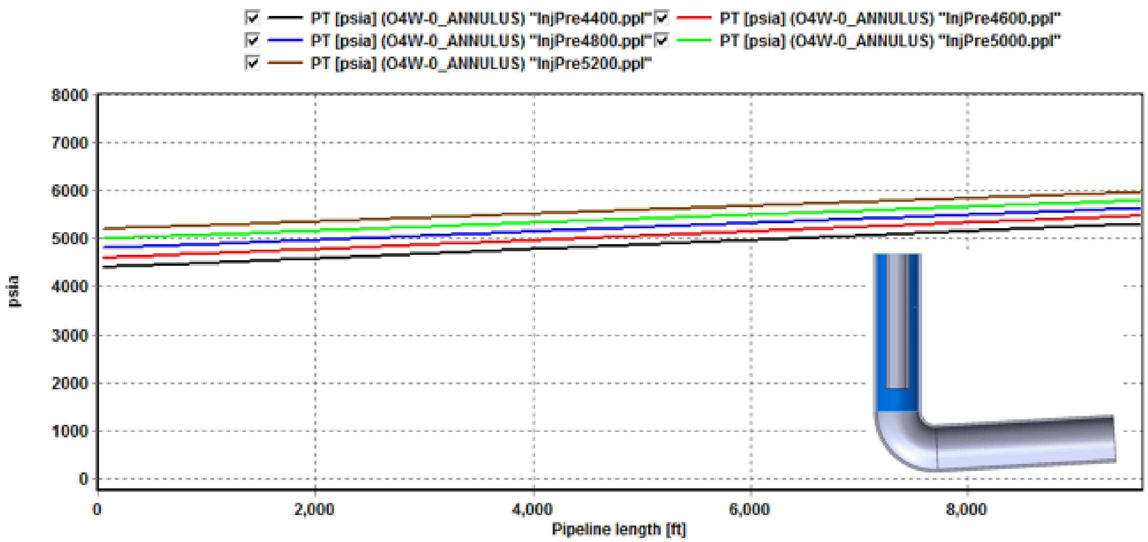


Figure 4.2. Pressure At Time=60min Of Annulus Due To Nitrogen Pressure Variation

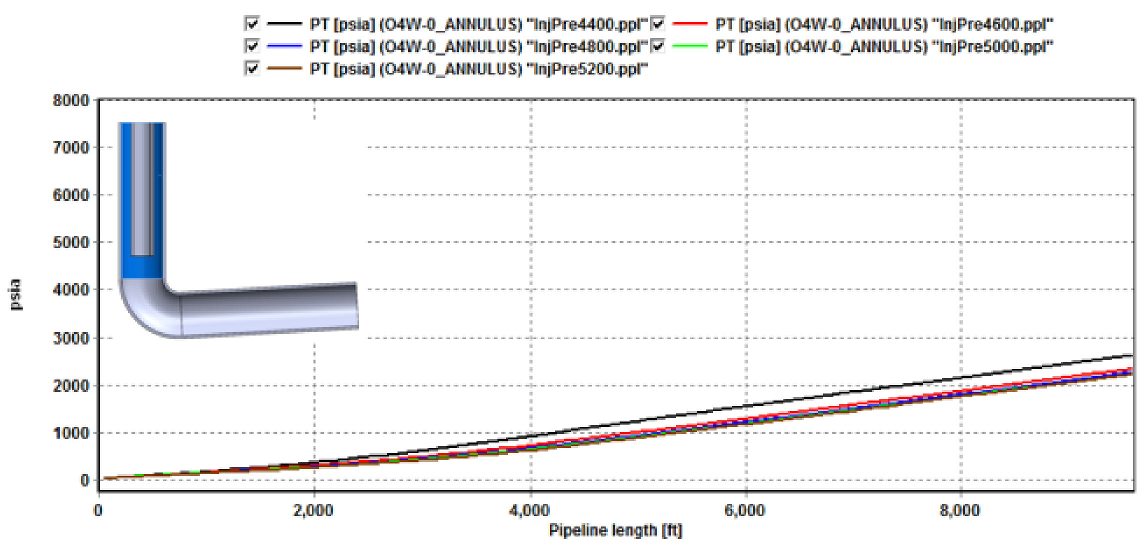


Figure 4.3. Pressure At Annulus After Unloading Process Finished

Figure 4.4 shows the pressure profile for the Tubing at the starting point. Figure 4.5 shows the pressure when the nitrogen reaches 60min of injection.

Figure 4.6 illustrates the pressure profile for the tubing when the unloading process ends.

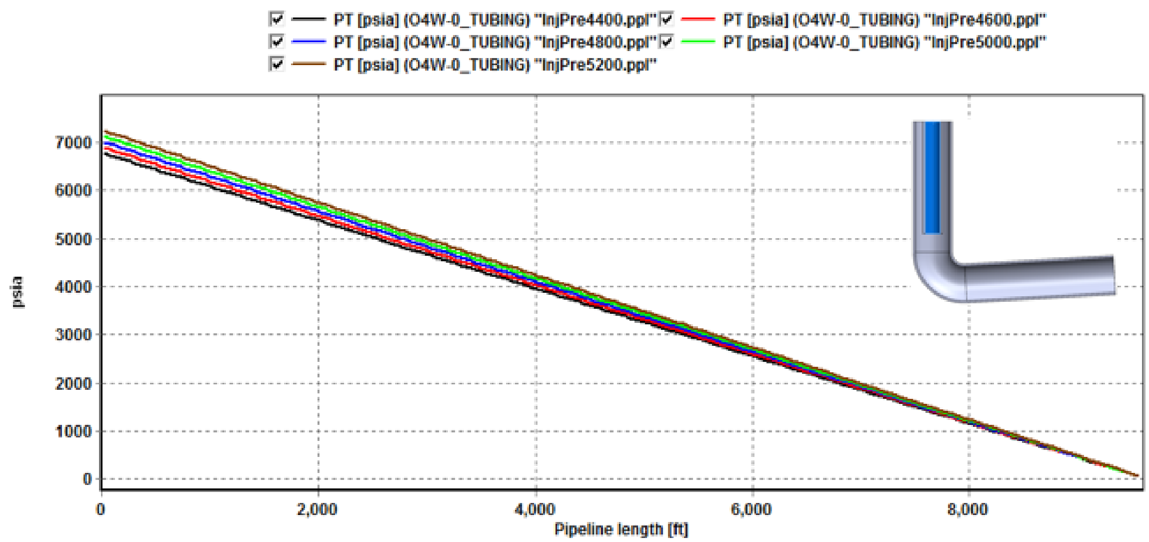


Figure 4.4. Pressure At Time=0min Of Tubing Due To Nitrogen Pressure Variation

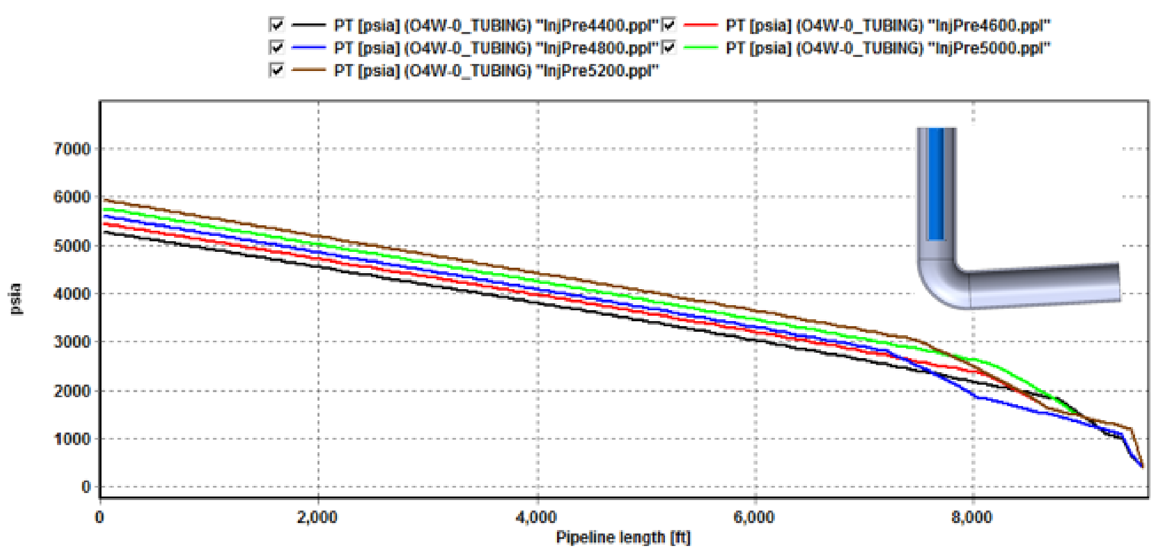


Figure 4.5. Pressure At Time=60min Of Tubing Due To Nitrogen Pressure Variation

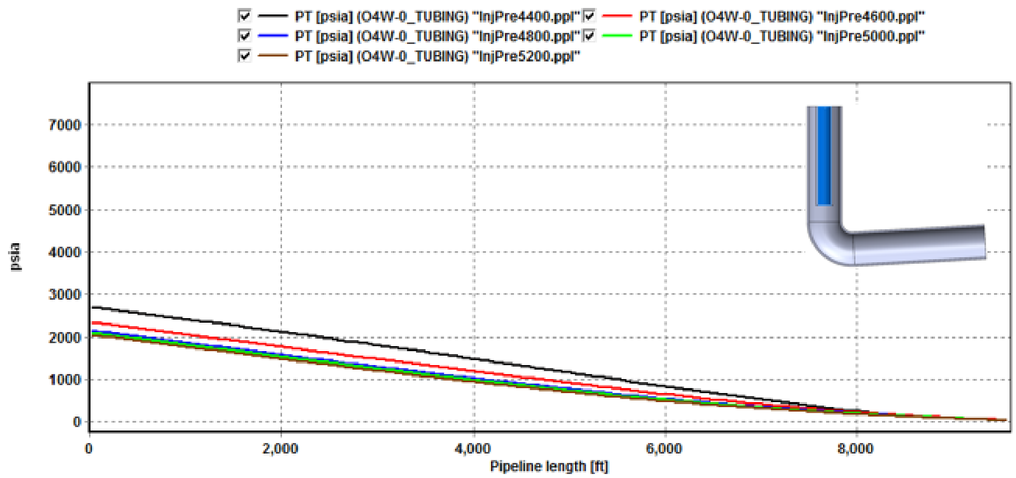


Figure 4.6. Pressure At Tubing After Unloading Process Finished

Figure 4.7 represents the pressure profile for the wellbore (lateral section) at the beginning of the simulation.

Figure 4.8 shows the pressure at 60min. Figure 4.9 shows the pressure at the lateral when the unloading process ends, and gas production is restored.

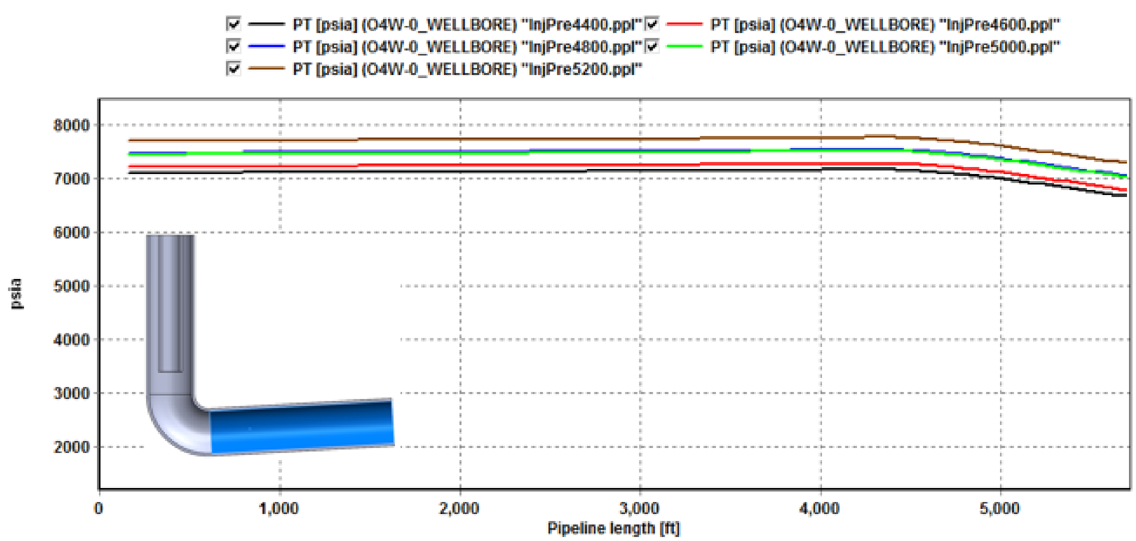


Figure 4.7. Pressure At Time=0min Of Lateral Due To Nitrogen Pressure Variation

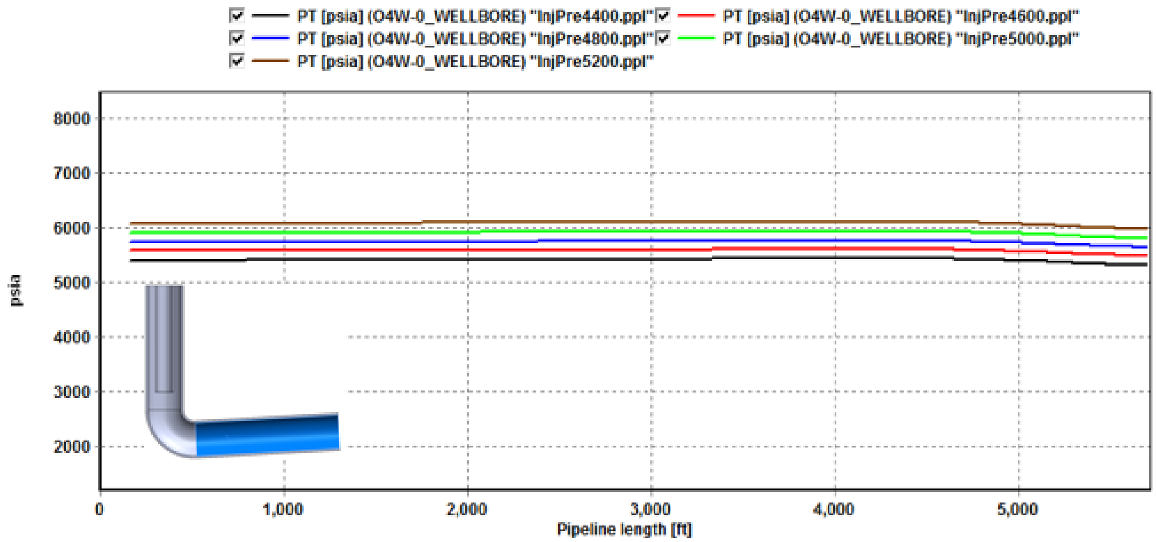


Figure 4.8. Pressure At Time=60min Of Lateral Due To Nitrogen Pressure Variation

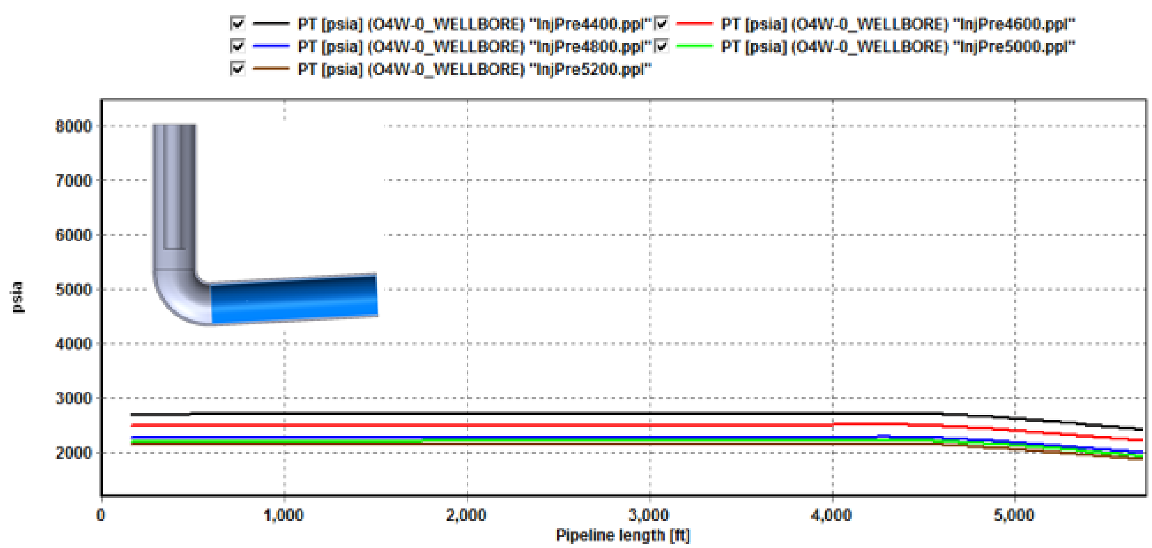


Figure 4.9. Pressure At Lateral After Unloading Process Finished

4.1.2. Hold-Up. Figure 4.10 shows the hold-up at the annulus when the unloading process starts. Figure 4.11 shows the hold-up reaches its lowest value after 12min of nitrogen injection.

Figure 4.12 shows the hold-up for the annulus after the unloading process ends.

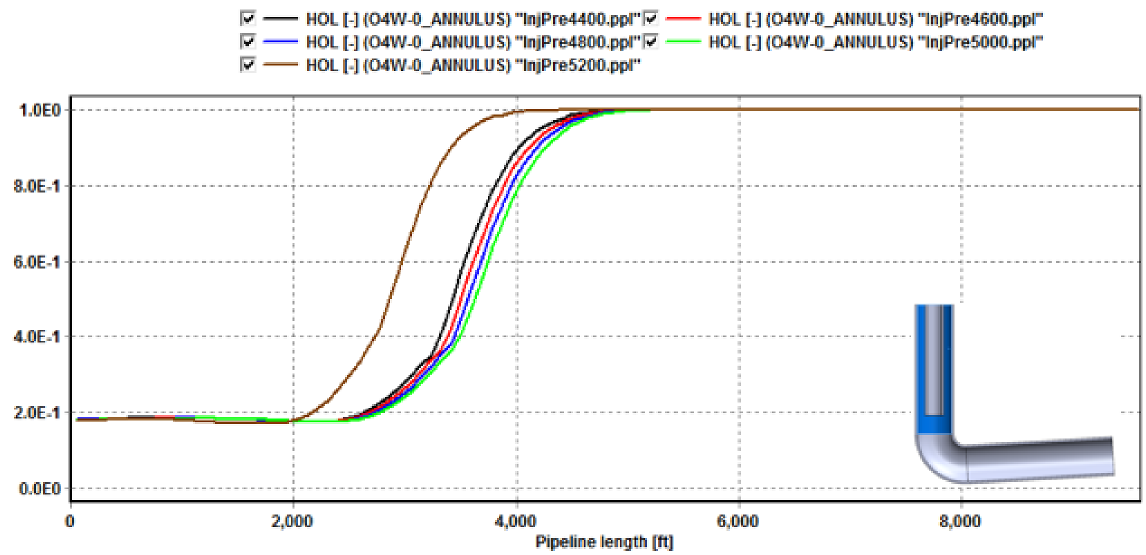


Figure 4.10. Hold-Up At Time=0min Of Annulus Due To Nitrogen Pressure Variation

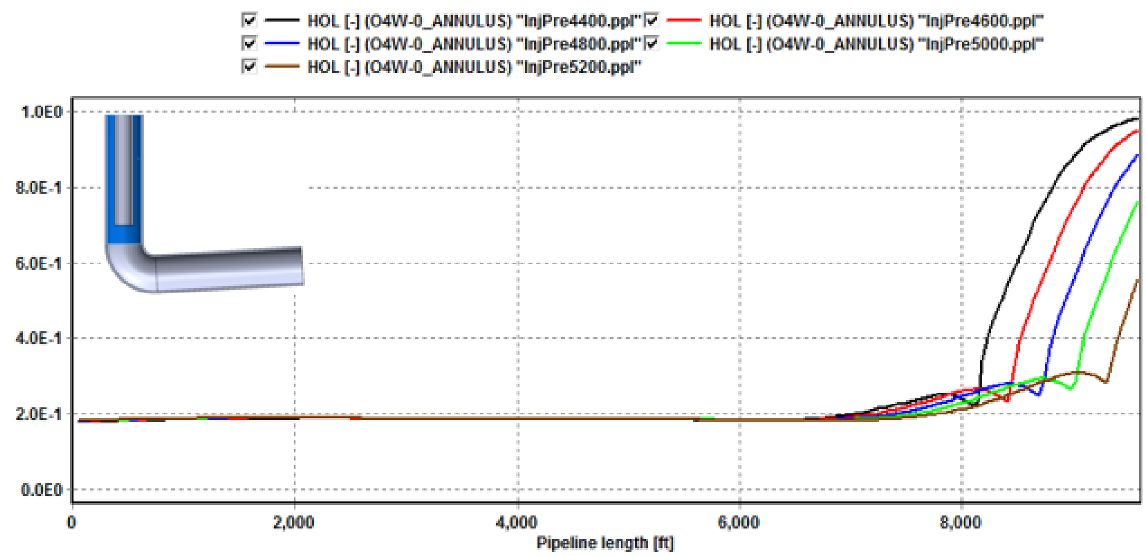


Figure 4.11. Hold-Up At Time=12min Of Annulus Due To Nitrogen Pressure Variation

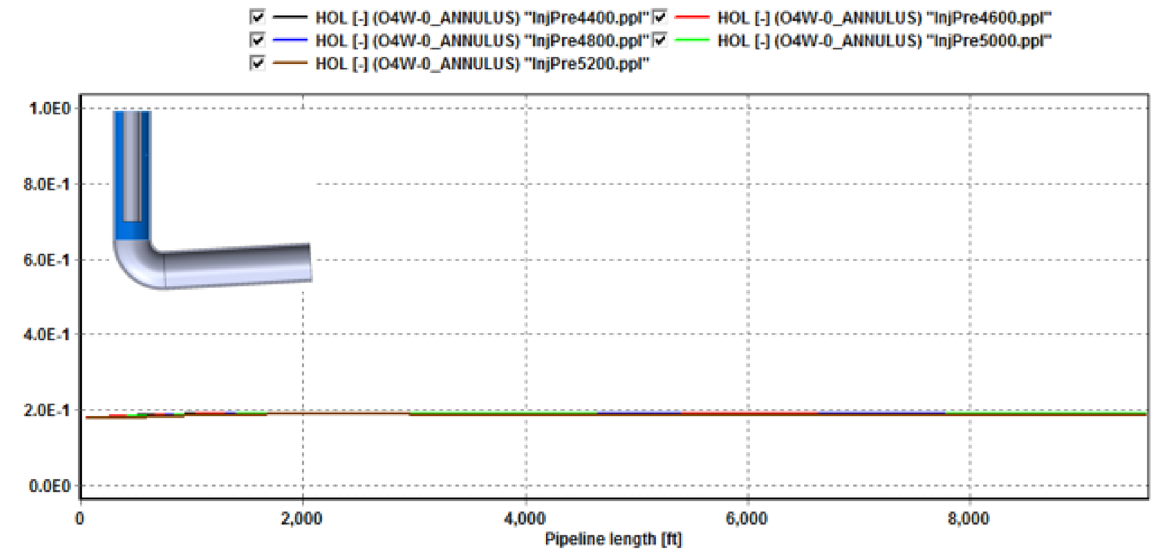


Figure 4.12. Hold-Up At Time=15min Of Annulus Due To Nitrogen Pressure Variation

Figure 4.13 shows the hold-up for the tubing when the simulation starts. Figure 4.14 illustrates the hold-up after 18min. Figure 4.15 indicates that the hold-up reached the lowest value for the tubing section after 22min of nitrogen injection.

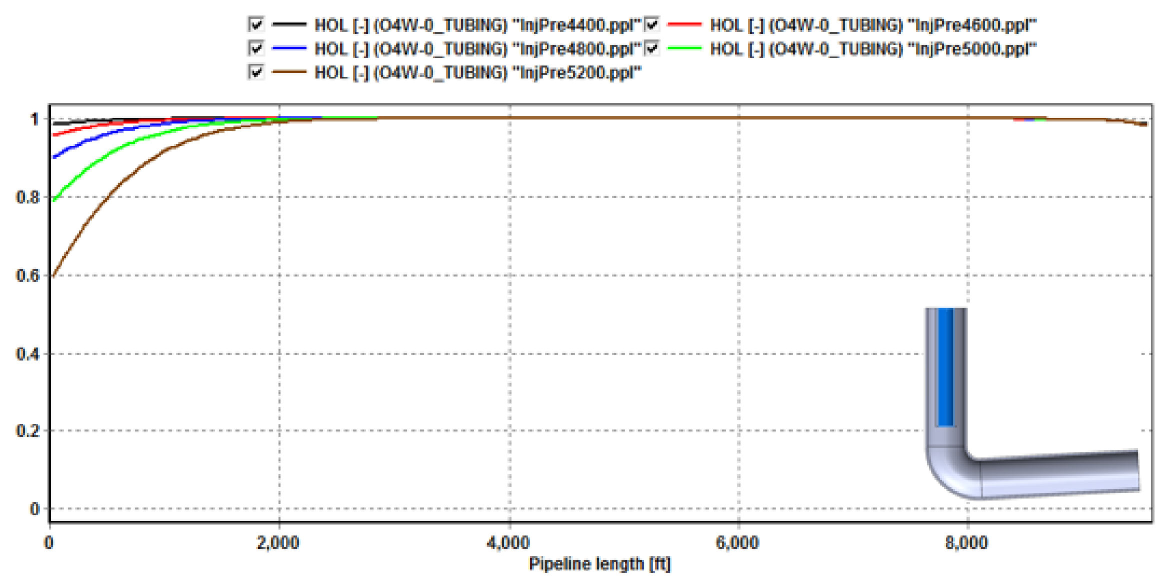


Figure 4.13. Hold-Up At Time=0min Of Tubing Due To Nitrogen Pressure Variation

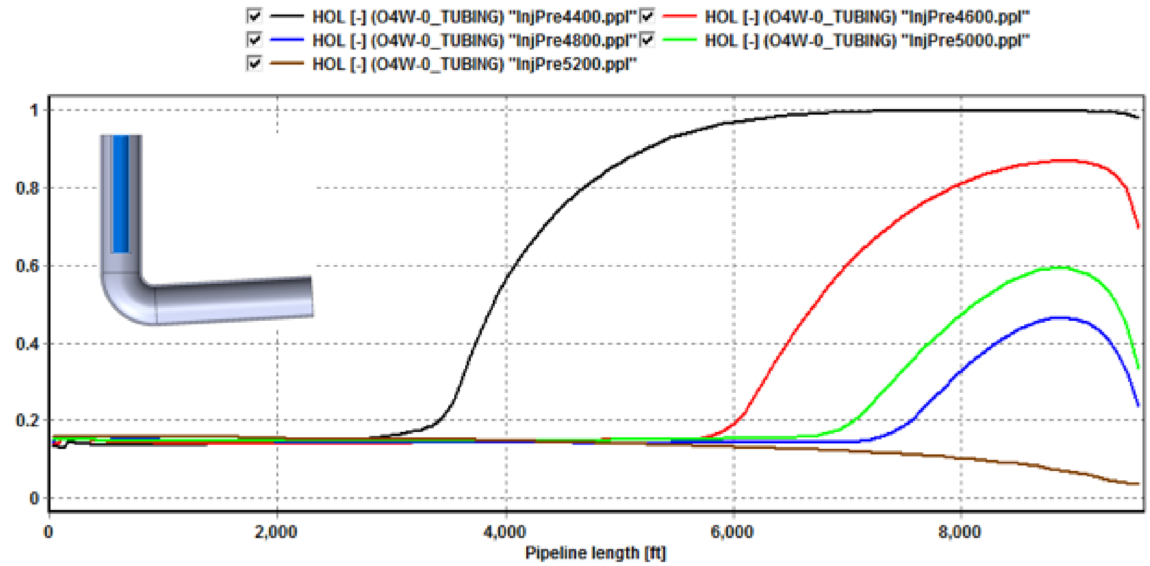


Figure 4.14. Hold-Up At Time=18min Of Tubing Due To Nitrogen Pressure Variation

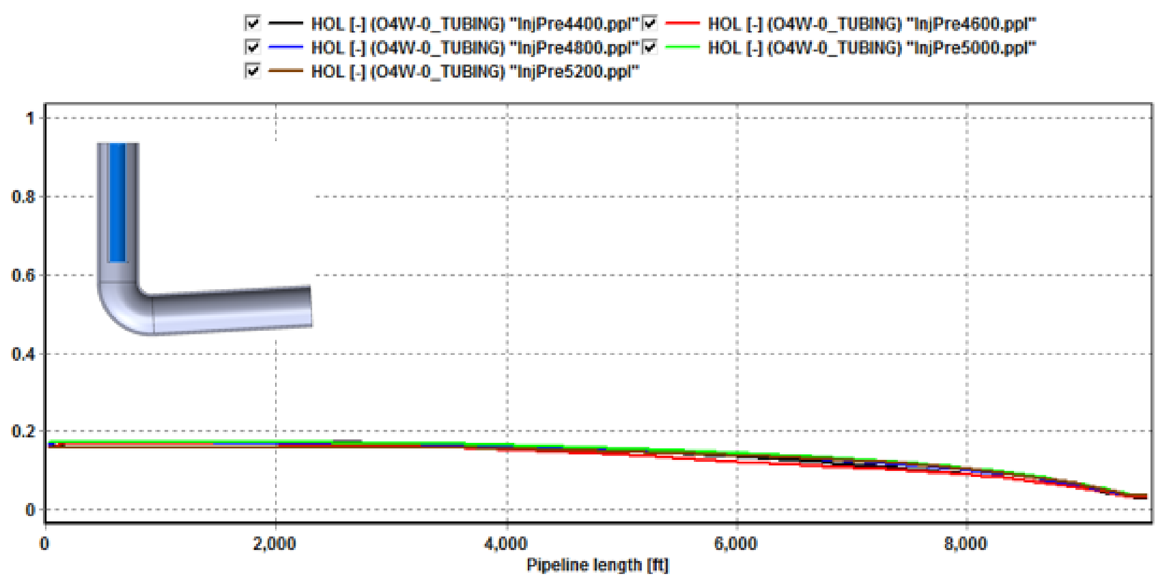


Figure 4.15. Hold-Up At Time=22min Of Tubing Due To Nitrogen Pressure Variation

Figure 4.16 shows the hold-up for the lateral section after 14min on nitrogen injection. Figure 4.17 shows the hold-up after 28min of injection. Figure 4.18 shows the hold-up for the lateral section after 60min of nitrogen injection.

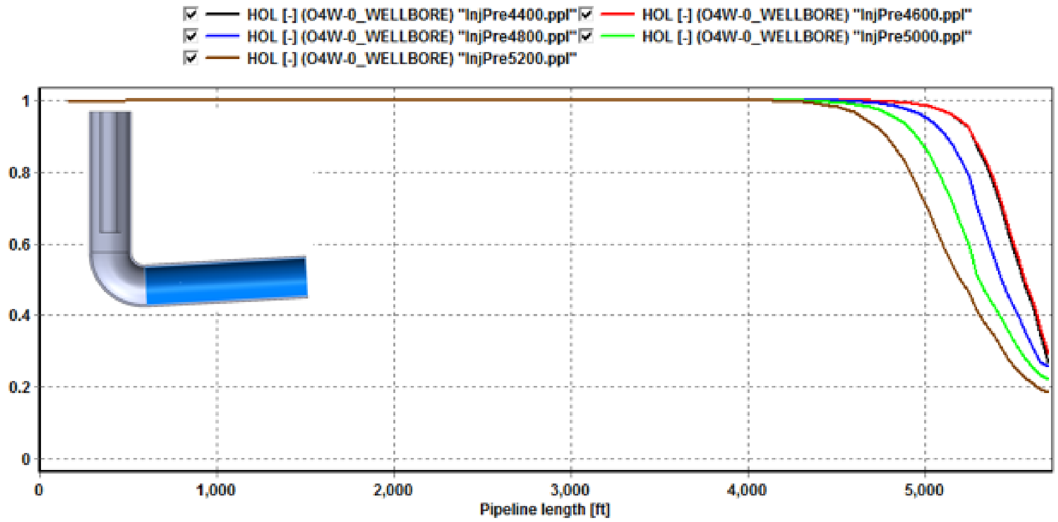


Figure 4.16. Hold-Up At Time=14min Of Lateral Due To Nitrogen Pressure Variation

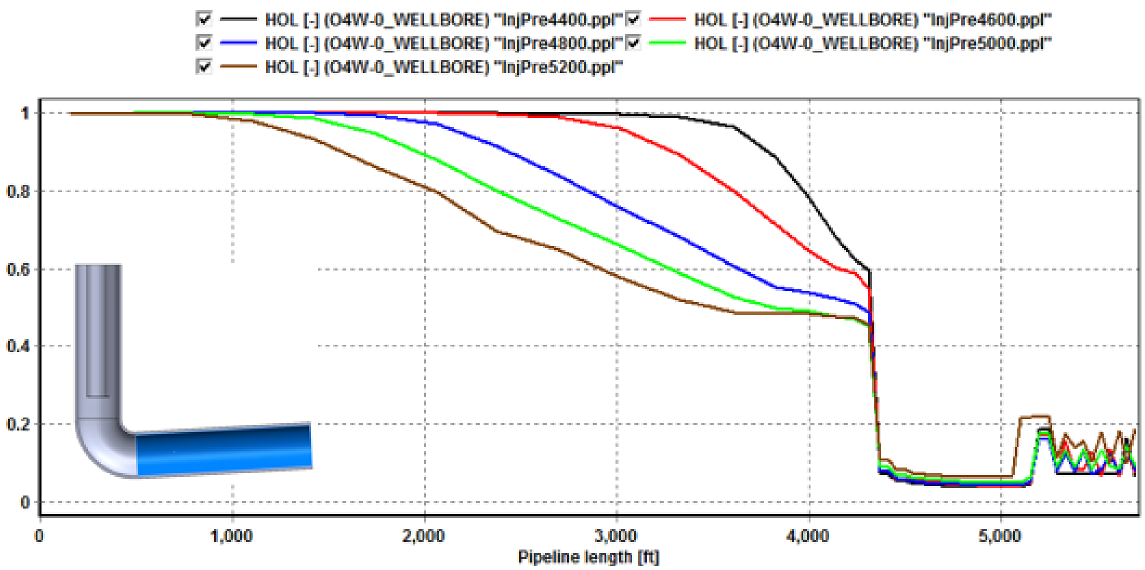


Figure 4.17. Hold-Up At Time=28min Of Lateral Due To Nitrogen Pressure Variation

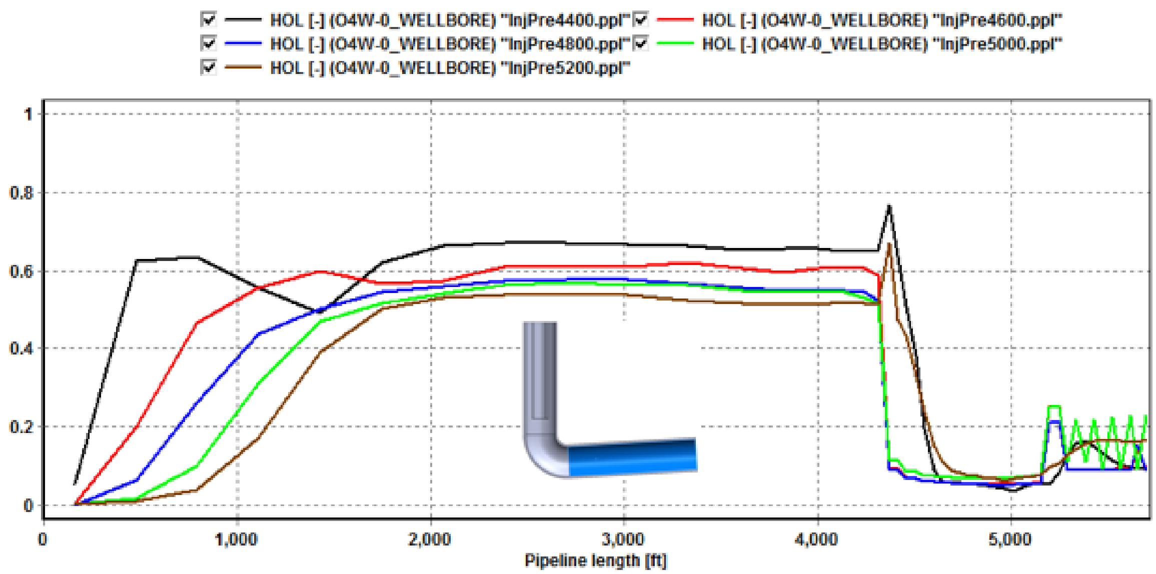


Figure 4.18. Hold-Up At Time=60min Of Lateral Due To Nitrogen Pressure Variation

4.2. VARIATION OF NITROGEN INJECTION MASS RATE

4.2.1. Pressure. Figure 4.19 shows the pressure for the annulus of the well when the unloading process starts.

Figure 4.20 illustrates the behavior of nitrogen for different values of pressure after 60min (time of unloading).

Figure 4.21 shows the pressure profile for all cases after the nitrogen stops being injected.

Figure 4.22 shows the pressure profile for the Tubing at the starting point. Figure 4.23 shows the pressure when the nitrogen reaches 60min of injection.

Figure 4.24 illustrates the pressure profile for the tubing when the unloading process ends.

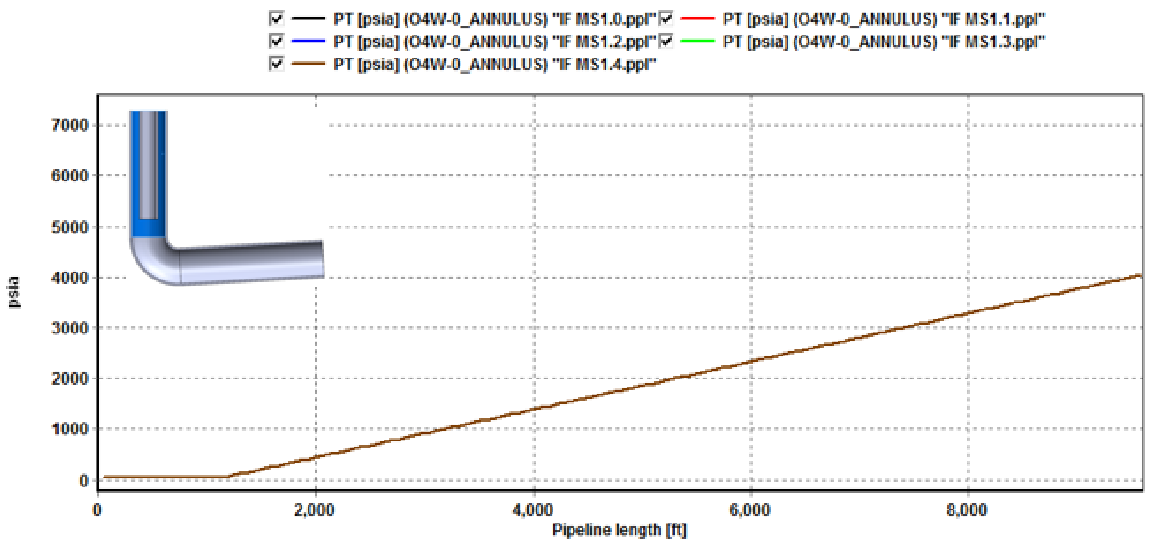


Figure 4.19. Pressure At Time=0min Of Annulus Due To Nitrogen Injection Mass Rate Variation

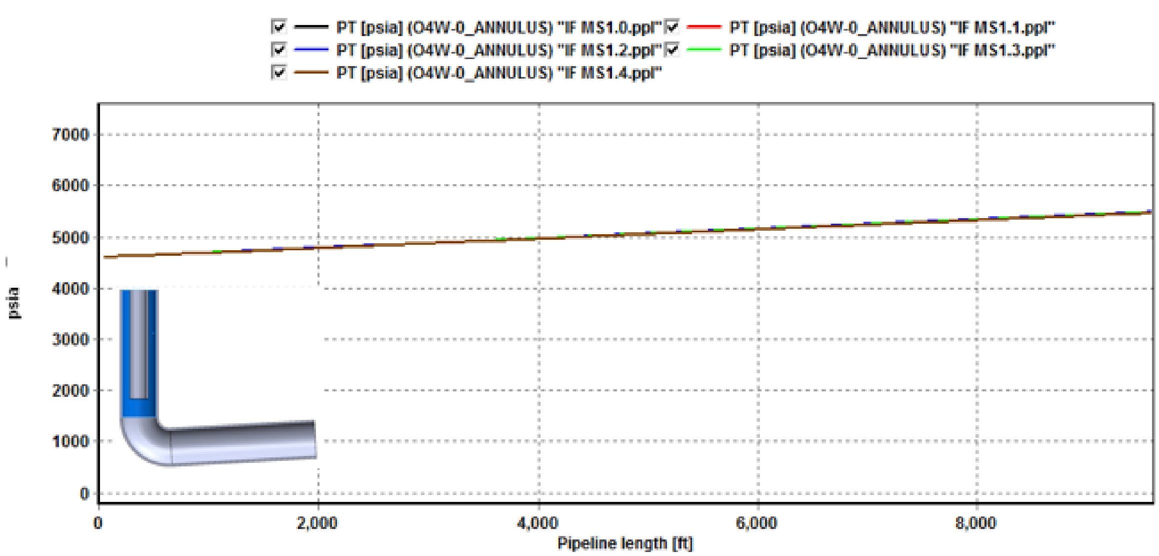


Figure 4.20. Pressure At Time=60min Of Annulus Due To Nitrogen Injection Mass Rate Variation

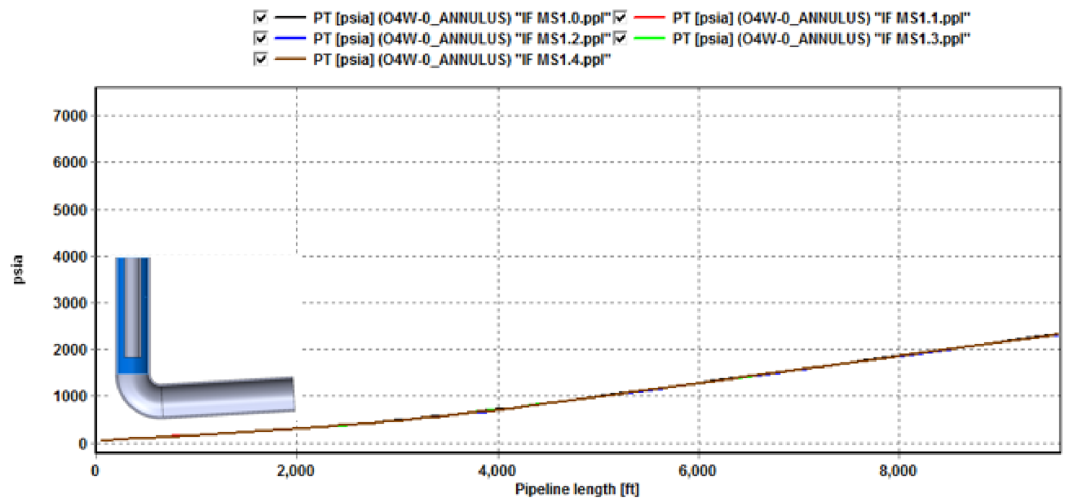


Figure 4.21. Pressure At Annulus After Unloading Process Finished

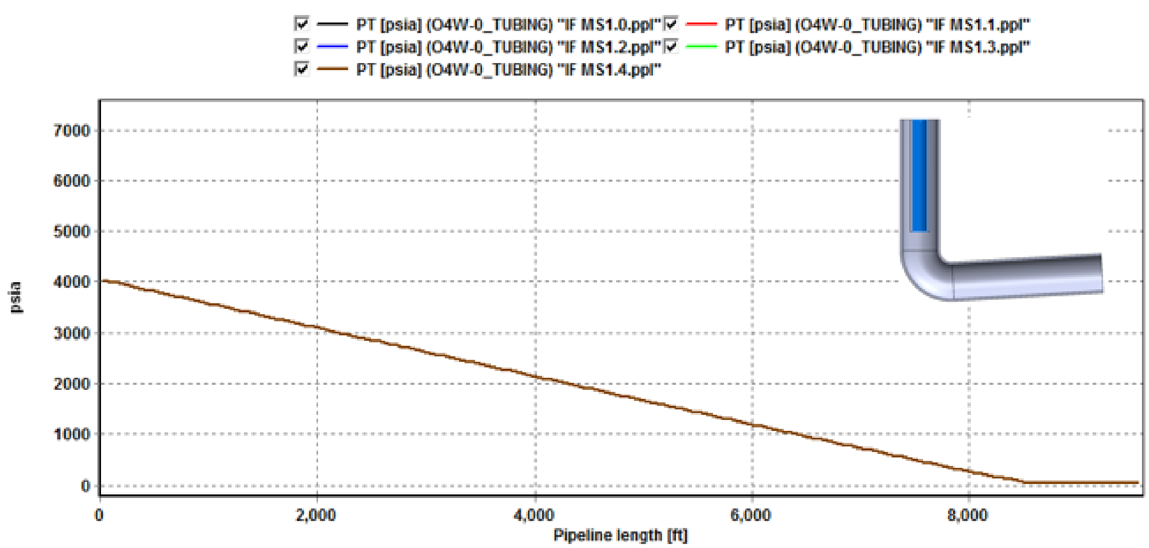


Figure 4.22. Pressure At Time=0min Of Tubing Due To Nitrogen Injection Mass Rate Variation

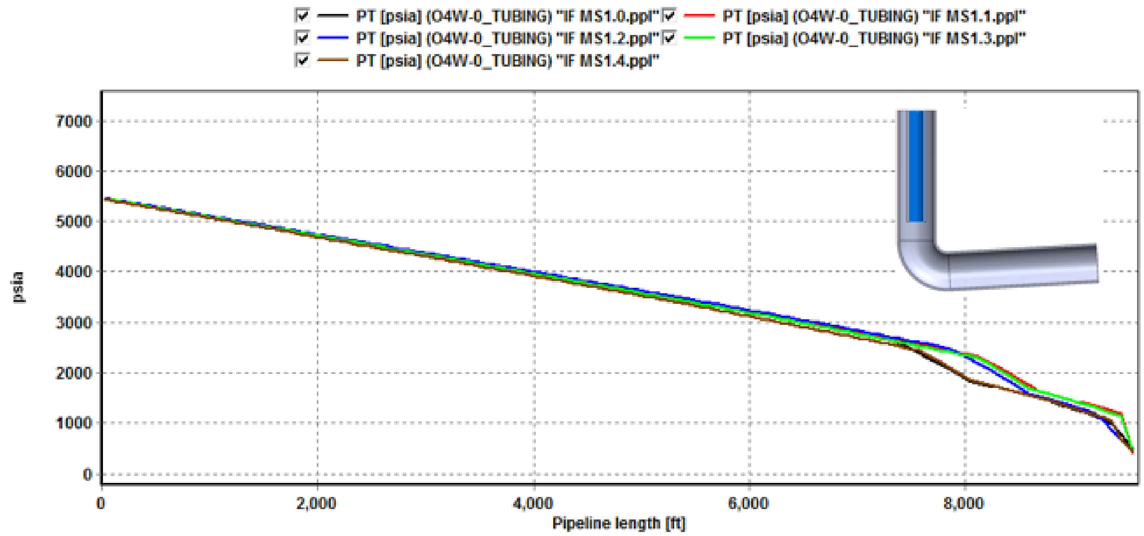


Figure 4.23. Pressure At Time=60min Of Tubing Due To Nitrogen Injection Mass Rate Variation

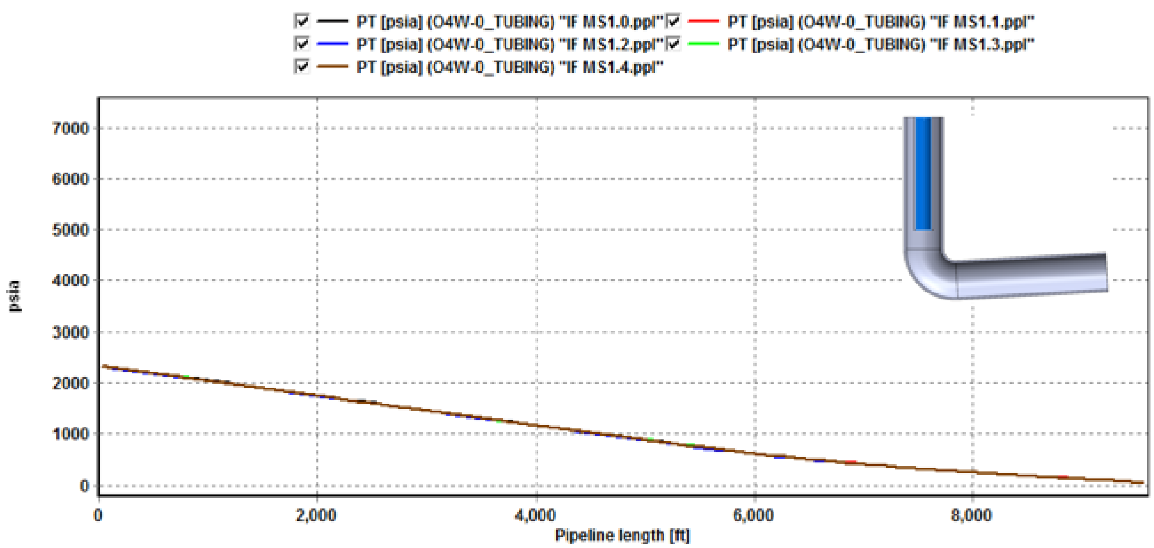


Figure 4.24. Pressure At Tubing After Unloading Process Finished

Figure 4.25 represents the pressure profile for the wellbore (lateral section) at the beginning of the simulation. Figure 4.26 shows the pressure at 60min. Figure 4.27 shows the pressure at the lateral when the unloading process ends, and the reservoir is ready to produce gas by its own.

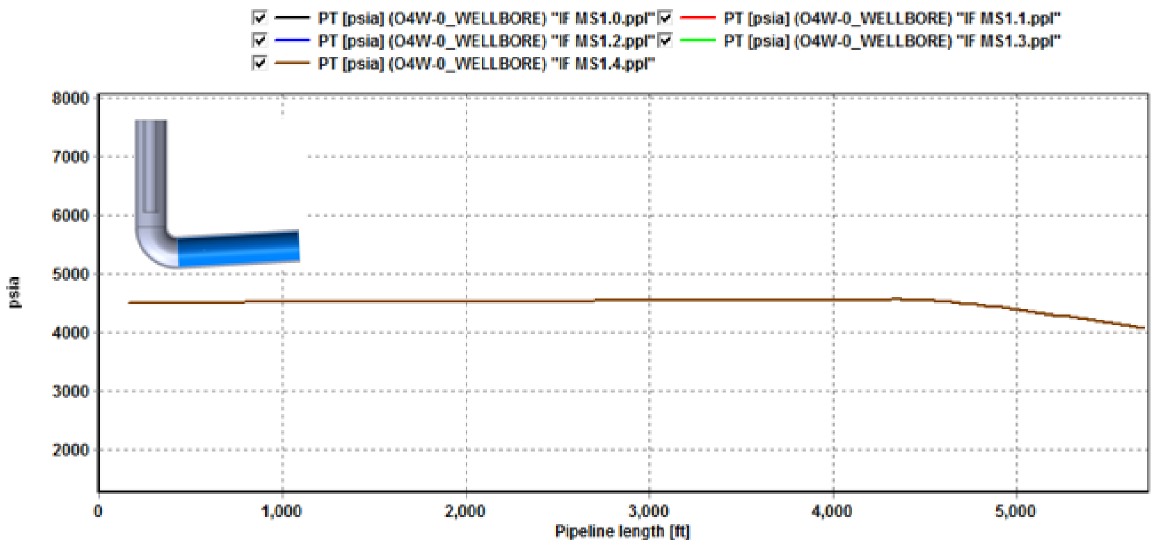


Figure 4.25. Pressure At Time=0min Of Lateral Due To Nitrogen Injection Mass Rate Variation

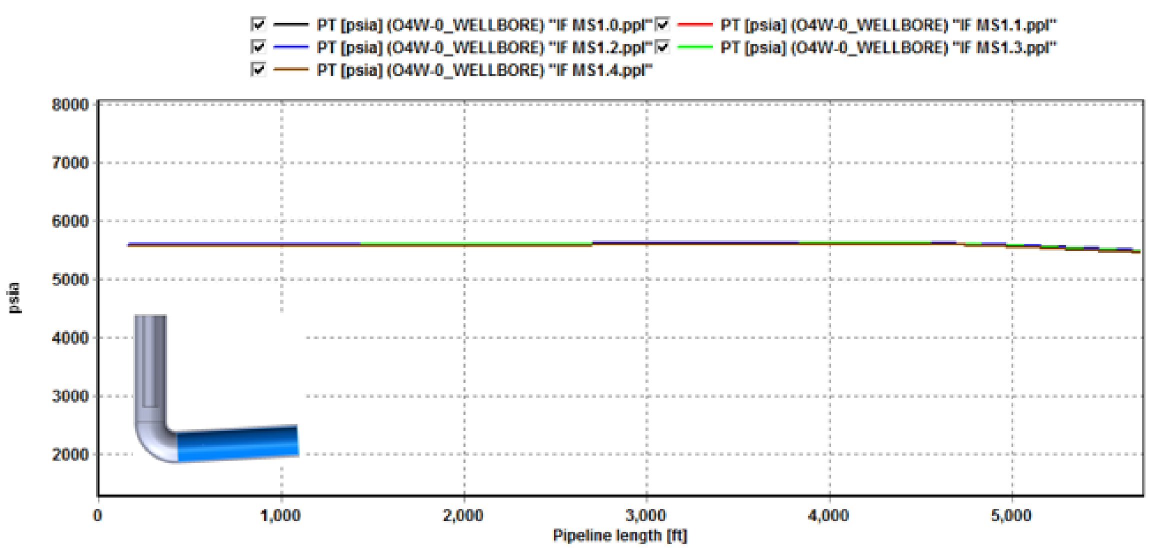


Figure 4.26. Pressure At Time=60min Of Lateral Due To Nitrogen Injection Mass Rate Variation

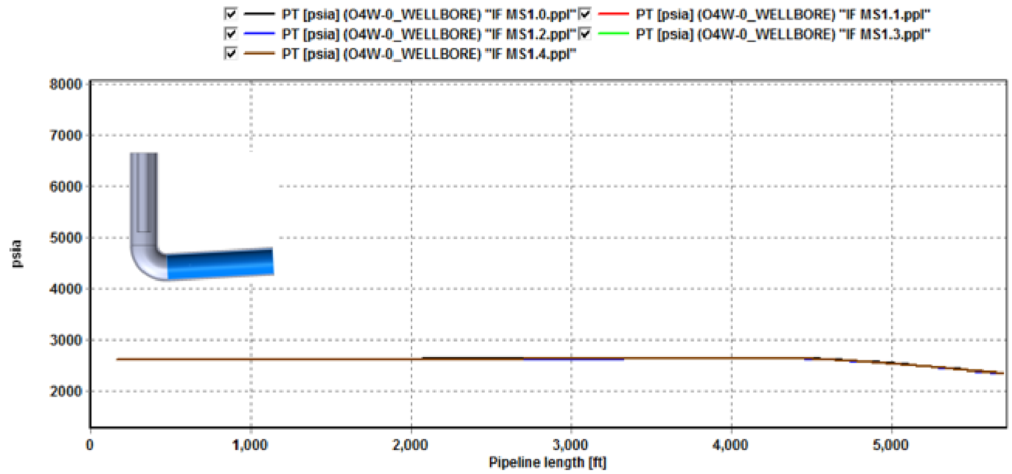


Figure 4.27. Pressure At Lateral After Unloading Process Finished

4.2.2. Hold-Up. Figure 4.28 shows the hold-up at the annulus when the unloading process starts. Figure 4.29 shows the hold-up reaches its lowest value after 12min of nitrogen injection. Figure 4.30 shows the hold-up for the annulus after the unloading process ends.

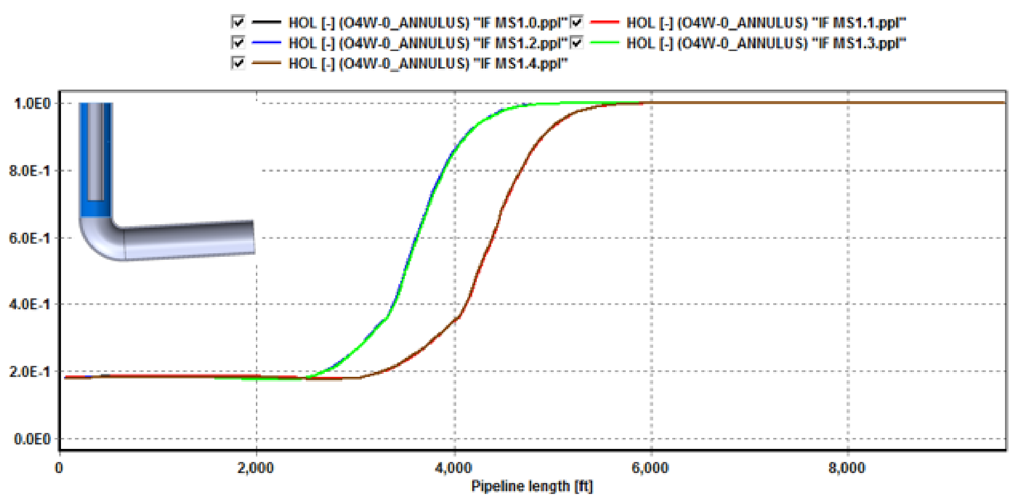


Figure 4.28. Hold-Up At Time=0min Of Annulus Due To Nitrogen Injection Mass Rate Variation

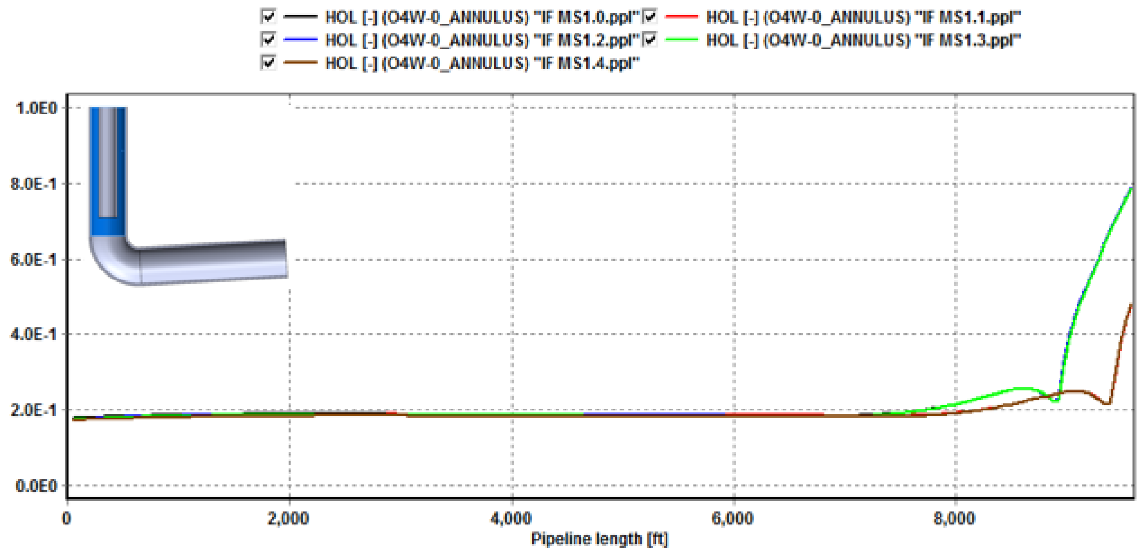


Figure 4.29. Hold-Up At Time=12min Of Annulus Due To Nitrogen Injection Mass Rate Variation

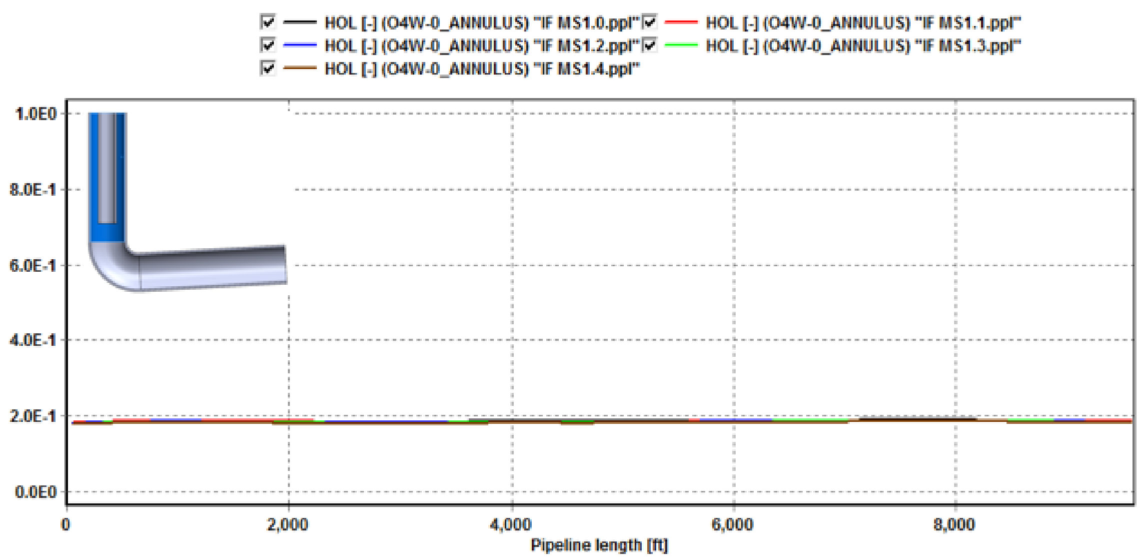


Figure 4.30. Hold-Up At Time=15min Of Annulus Due To Nitrogen Injection Mass Rate Variation

Figure 4.31shows the hold-up for the tubing when the simulation starts. Figure 4.32 illustrates the hold-up after 18min.

Figure 4.33 indicates that the hold-up reached the lowest value for the tubing section after 21min of nitrogen injection.

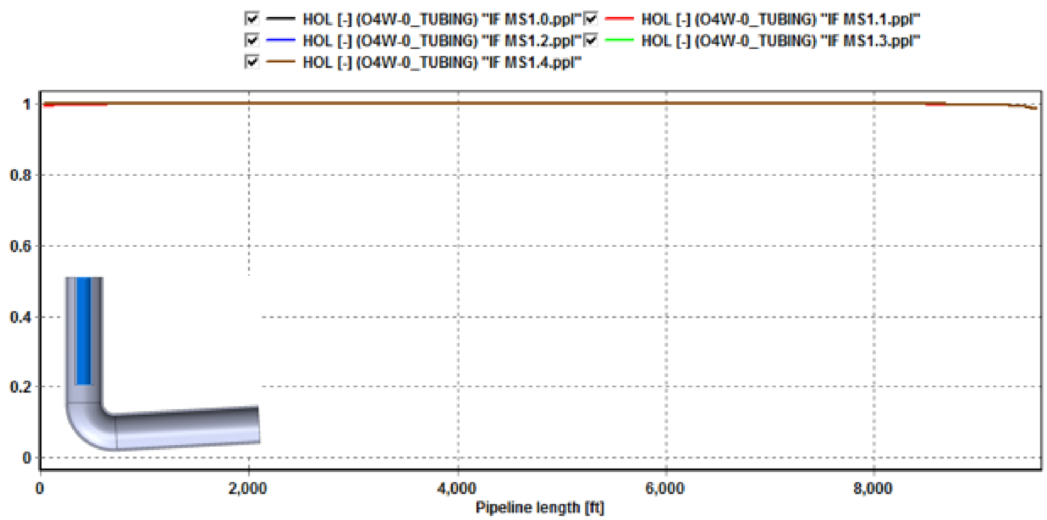


Figure 4.31. Hold-Up At Time=0min Of Tubing Due To Nitrogen Injection Mass Rate Variation

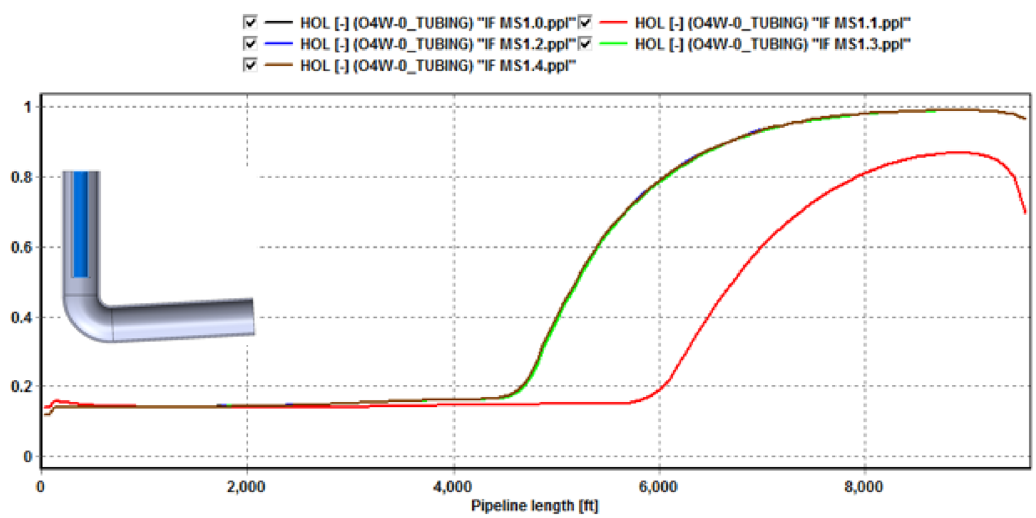


Figure 4.32. Hold-Up At Time=18min Of Tubing Due To Nitrogen Injection Mass Rate Variation

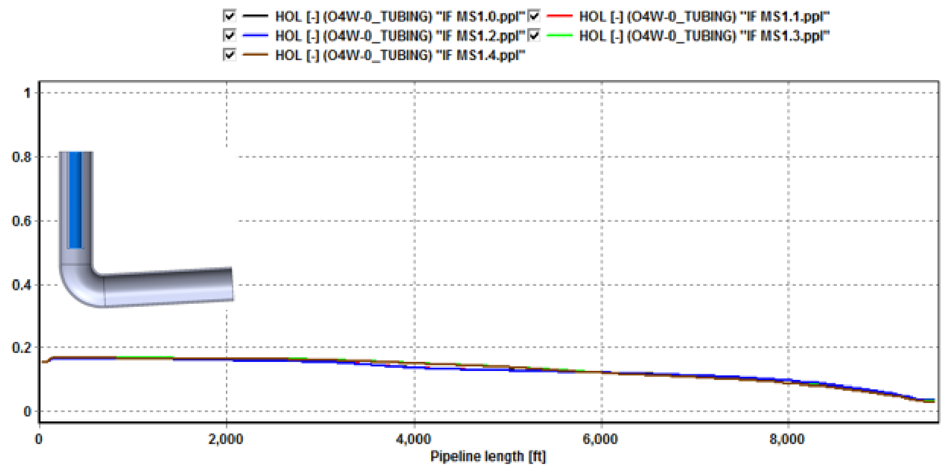


Figure 4.33. Hold-Up At Time=21min Of Tubing Due To Nitrogen Injection Mass Rate Variation

Figure 4.34 shows the hold-up for the lateral section after 14min of nitrogen injection. Figure 4.35 shows the hold-up after 28min of injection.

Figure 4.36 shows the hold-up for the lateral section after 60min of nitrogen injection.

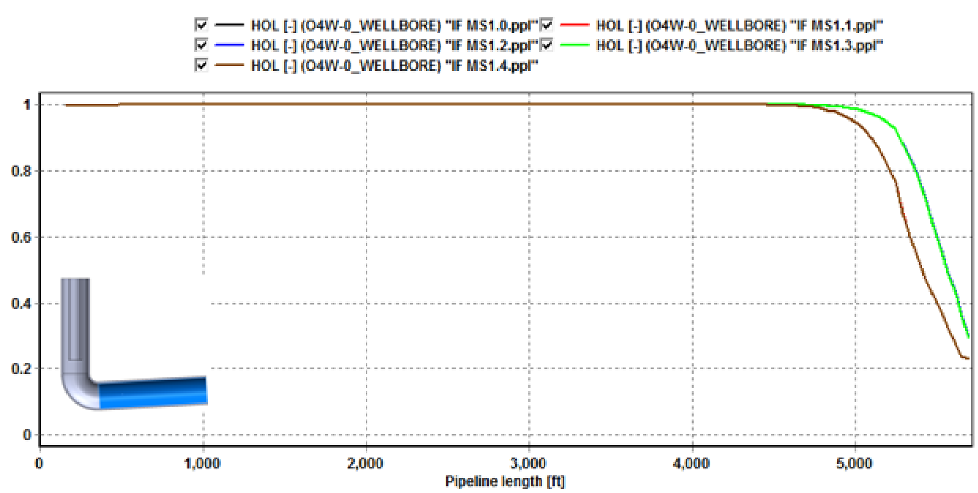


Figure 4.34. Hold-Up At Time=14min Of Lateral Due To Nitrogen Injection Mass Rate Variation

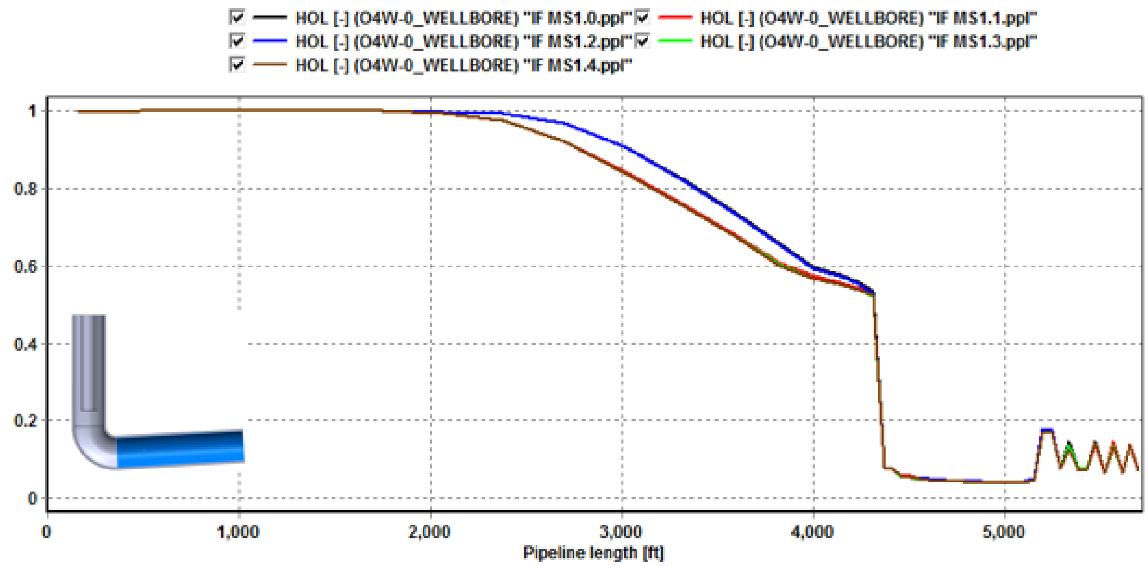


Figure 4.35. Hold-Up At Time=28min Of Lateral Due To Nitrogen Injection Mass Rate Variation

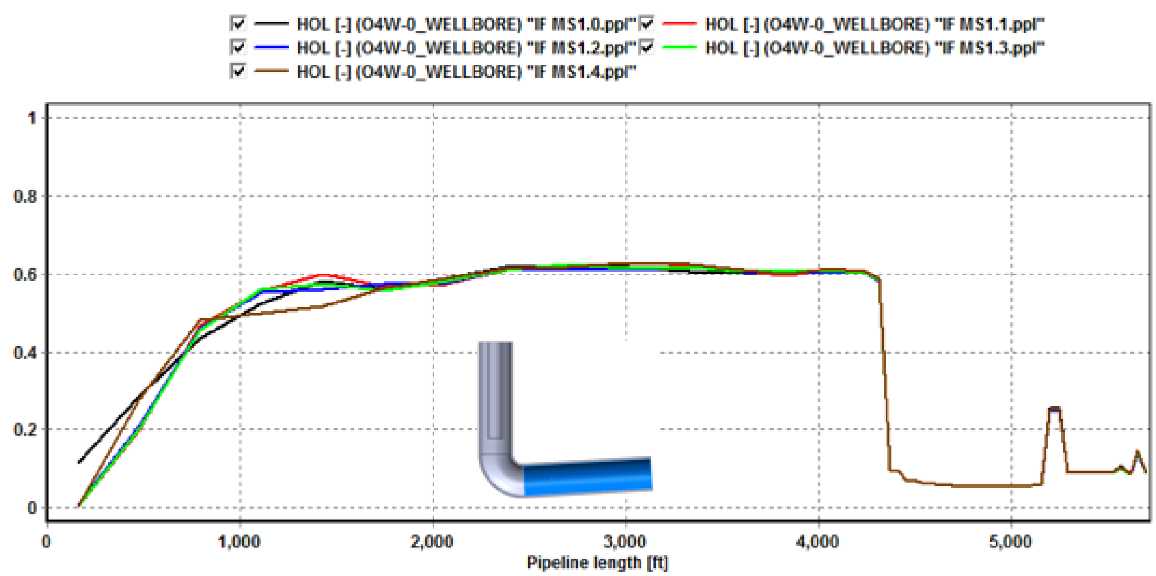


Figure 4.36. Hold-Up At Time=60min Of Lateral Due To Nitrogen Injection Mass Rate Variation

4.3. VARIATION OF EOT (TUBING SETTING DEPTH)

4.3.1. Pressure. Figure 4.37 shows the pressure for the annulus of the well when the unloading process starts.

Figure 4.38 illustrates the behavior of nitrogen for different values of pressure after 60min (time of unloading).

Figure 4.39 shows the pressure profile for all cases after the nitrogen stops being injected.

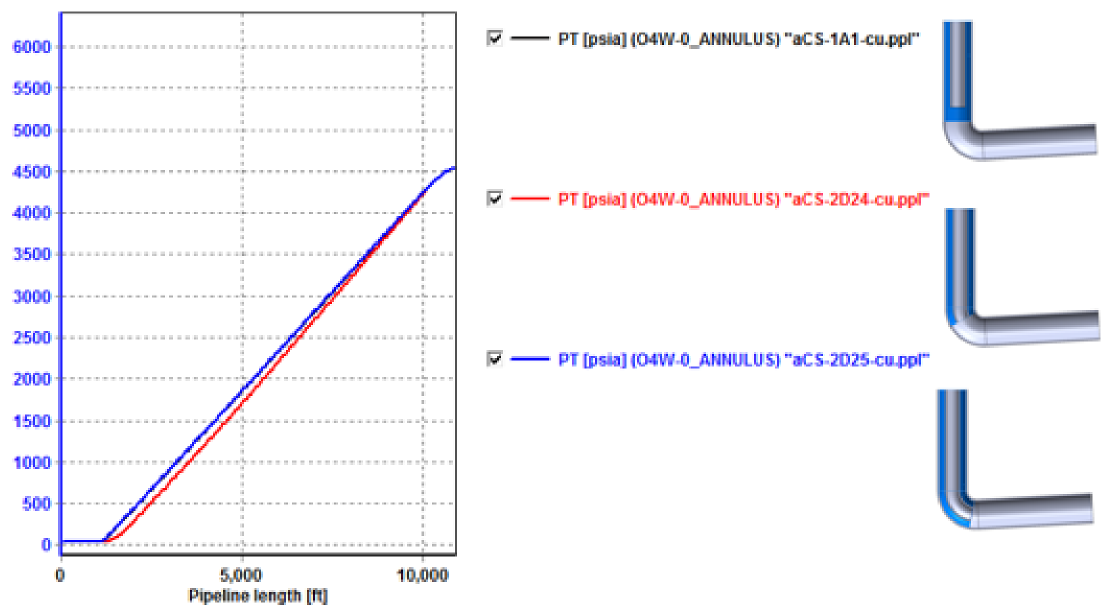


Figure 4.37. Pressure At Time=0min Of Annulus Due To Tubing Depth Variation

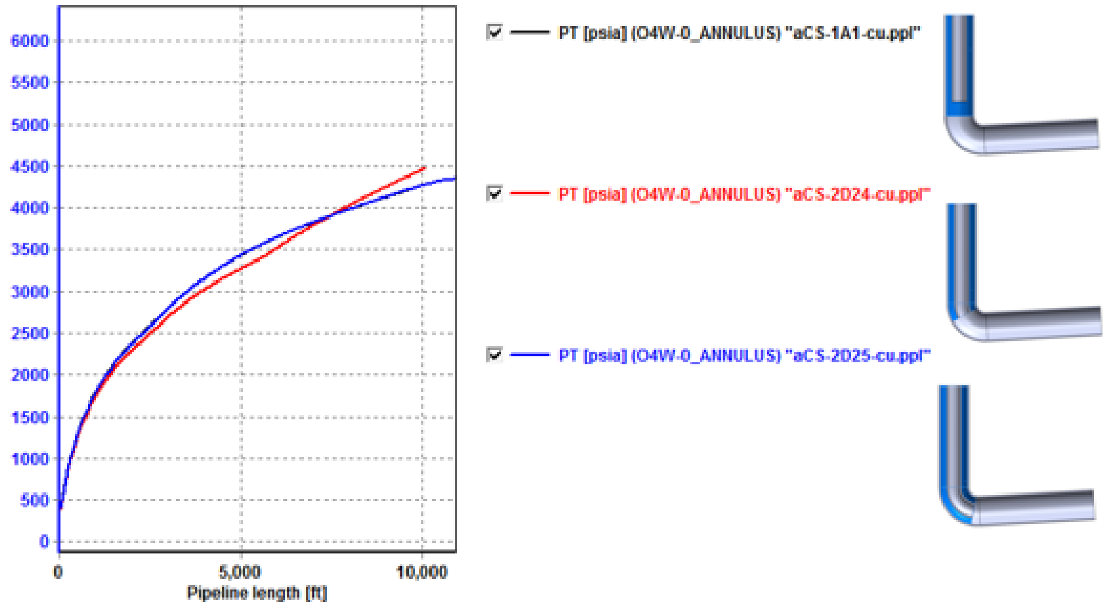


Figure 4.38. Pressure At Time=60min Of Annulus Due To Tubing Depth Variation

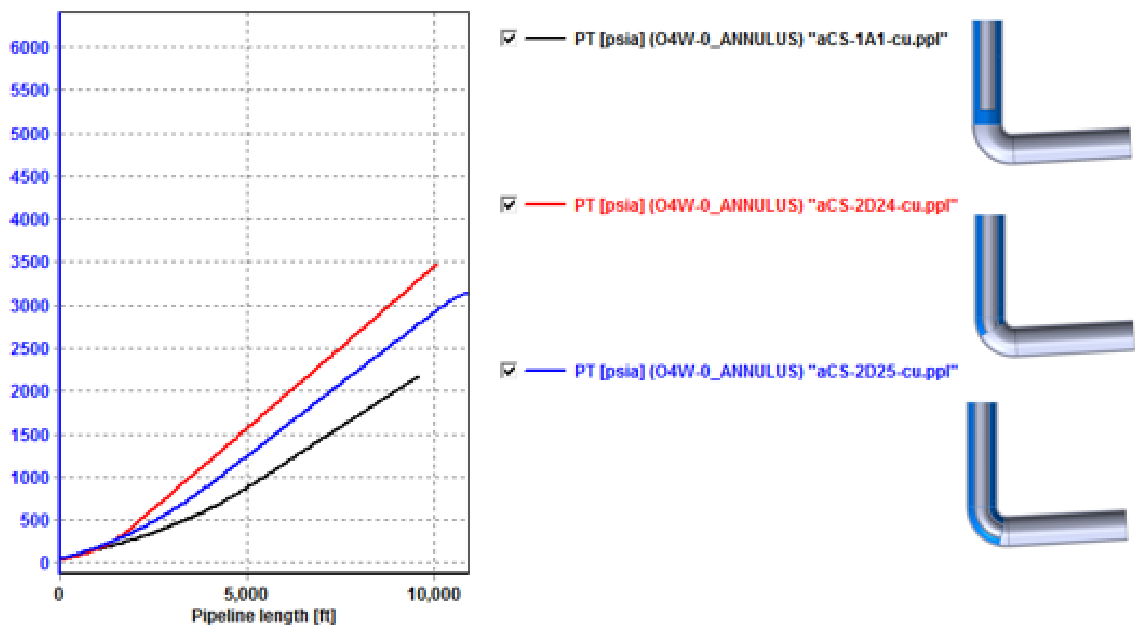


Figure 4.39. Pressure At Annulus After Unloading Process Finished

Figure 4.40 shows the pressure profile for the Tubing at the starting point. Figure 4.41 shows the pressure when the nitrogen reaches 60min of injection. Figure 4.42 illustrates the pressure profile for the tubing when the unloading process ends.

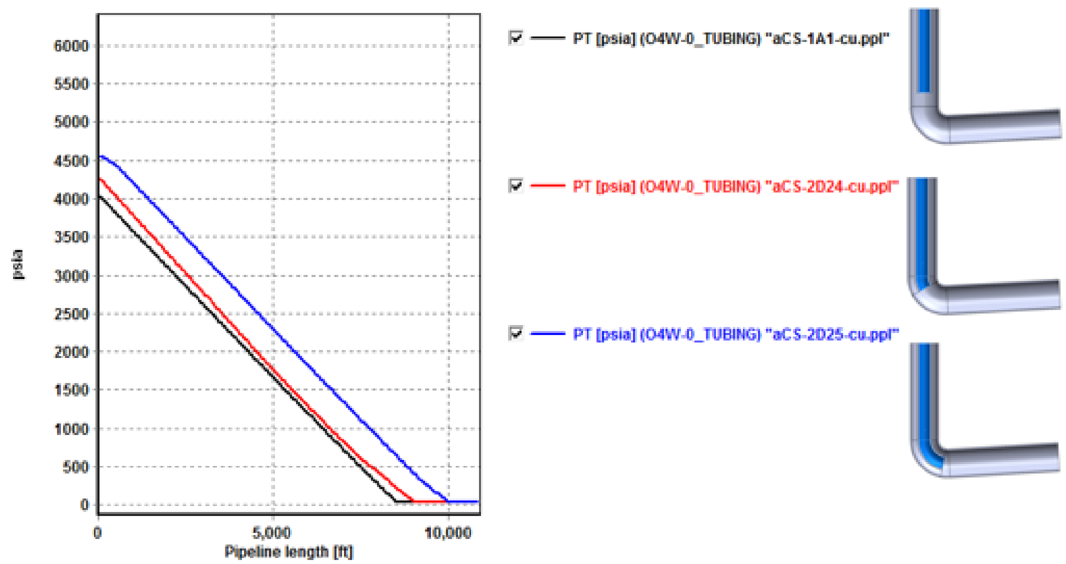


Figure 4.40. Pressure At Time=0min Of Tubing Due To Tubing Depth Variation

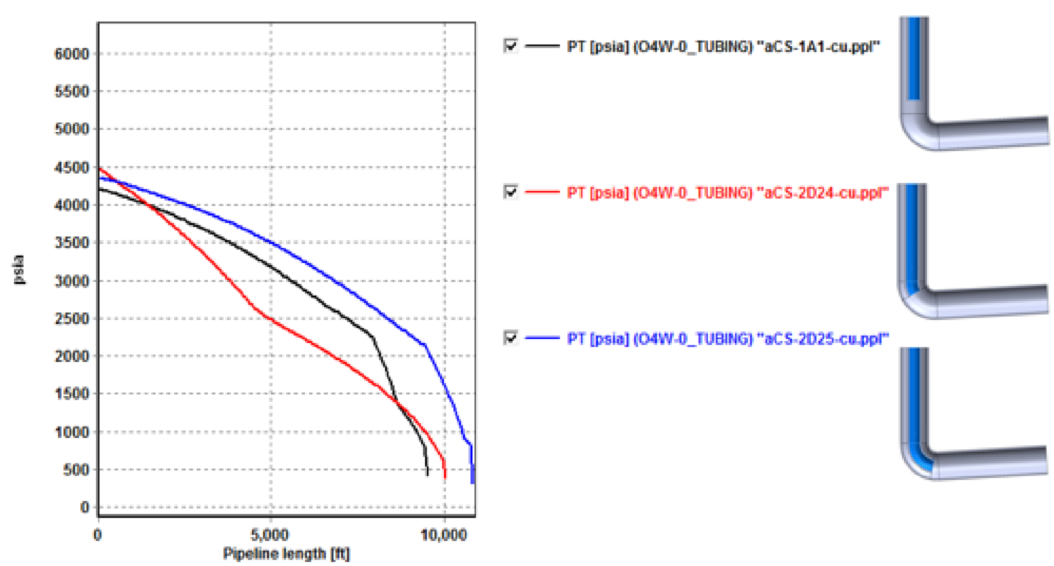


Figure 4.41. Pressure At Time=60min Of Tubing Due To Tubing Depth Variation

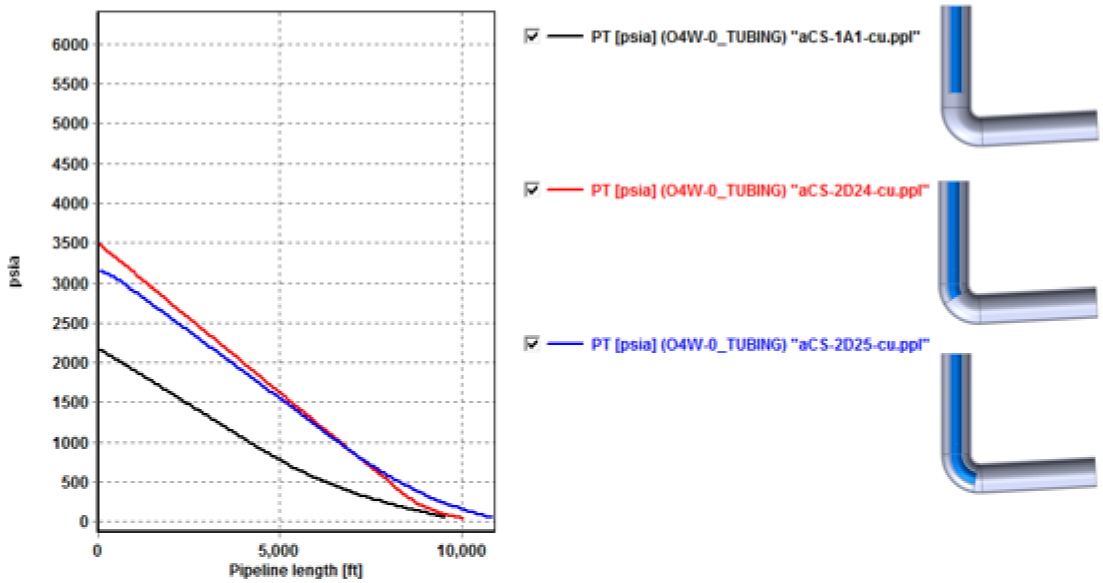


Figure 4.42. Pressure At Tubing After Unloading Process Finished

Figure 4.43 represents the pressure profile for the wellbore (lateral section) at the beginning of the simulation.

Figure 4.44 shows the pressure at 60min.

Figure 4.45 shows the pressure at the lateral when the unloading process ends, and the reservoir is ready to produce gas by its own.

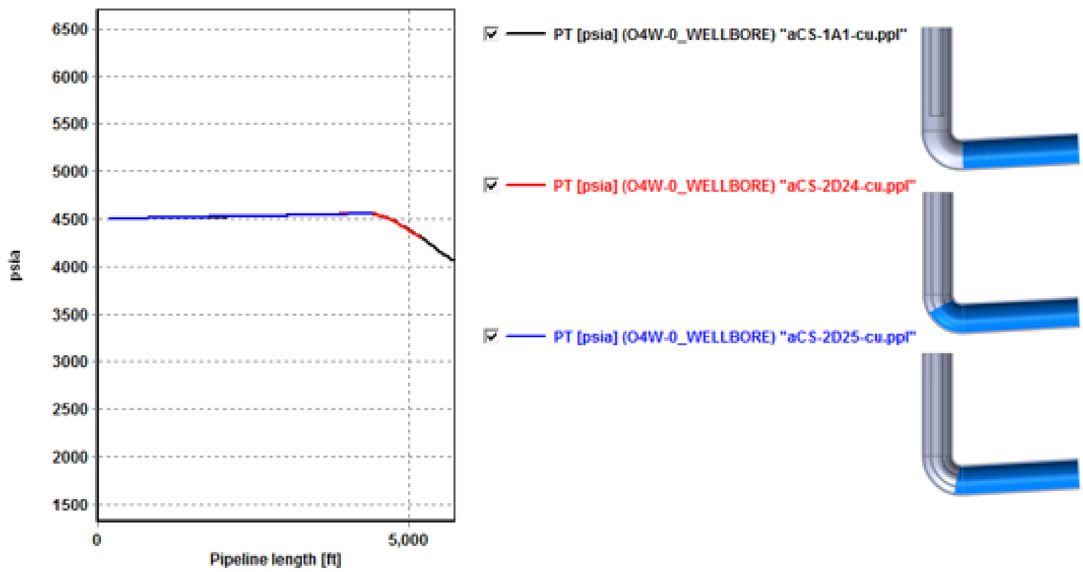


Figure 4.43. Pressure At Time=0min Of Lateral Due To Tubing Depth Variation

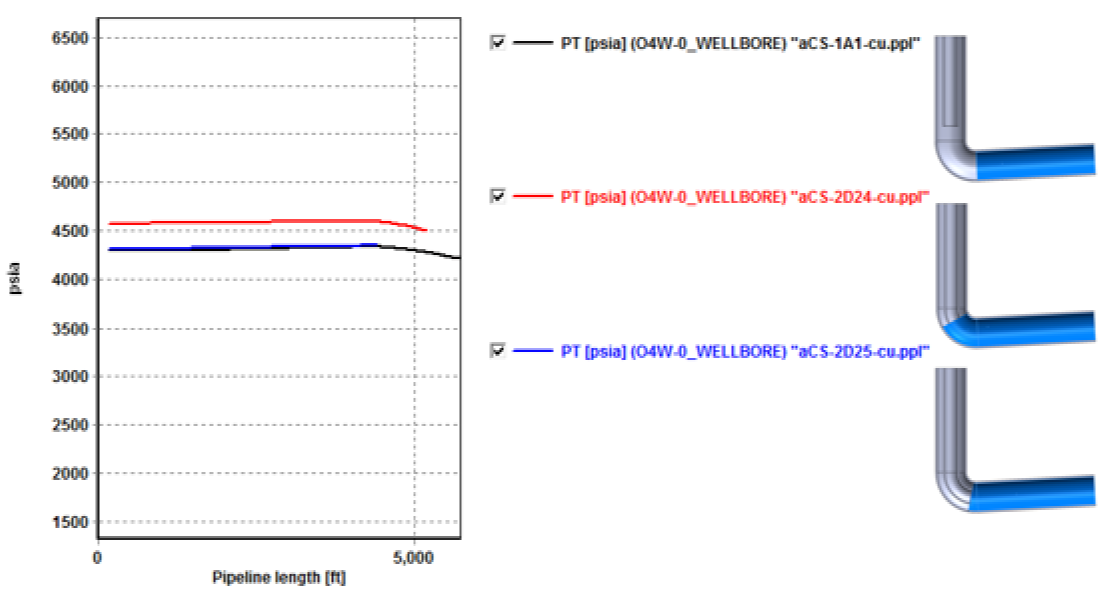


Figure 4.44. Pressure At Time=60min Of Lateral Due To Tubing Depth Variation

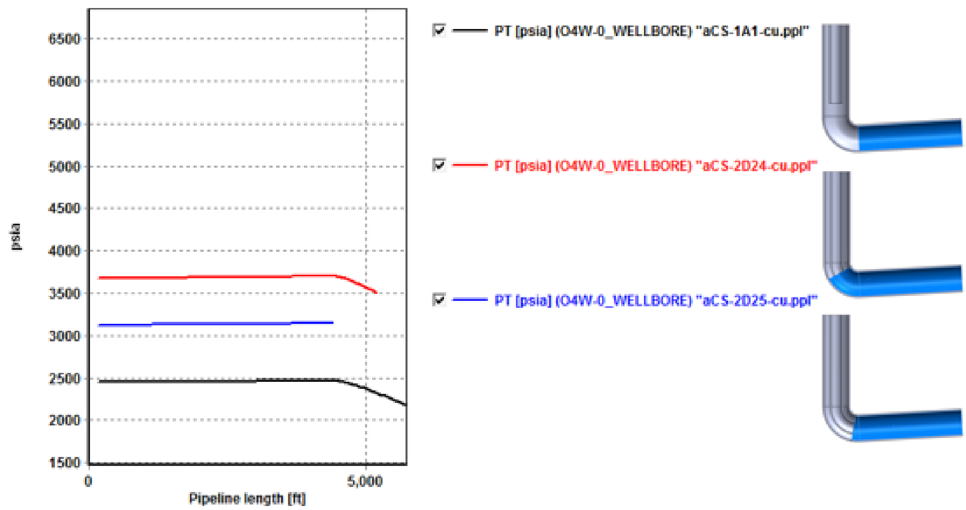


Figure 4.45. Pressure At Lateral After Unloading Process Finished

4.3.2. Hold-Up. Figure 4.46 shows the hold-up at the annulus when the unloading process starts. Figure 4.47 shows the hold-up reaches its lowest value after 12min of nitrogen injection. Figure 4.48 shows the hold-up for the annulus after the unloading process ends.

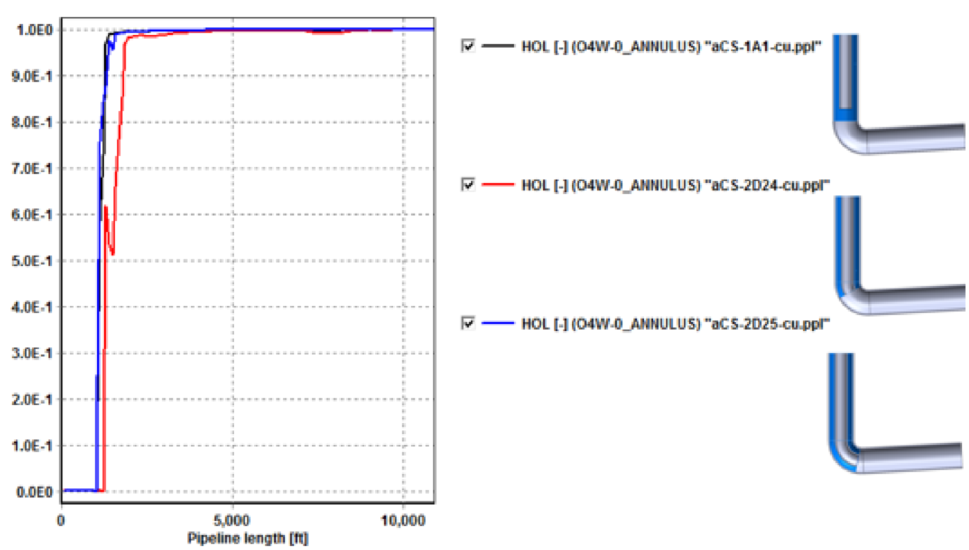


Figure 4.46. Hold-Up At Time=0min Of Annulus Due To Tubing Depth Variation

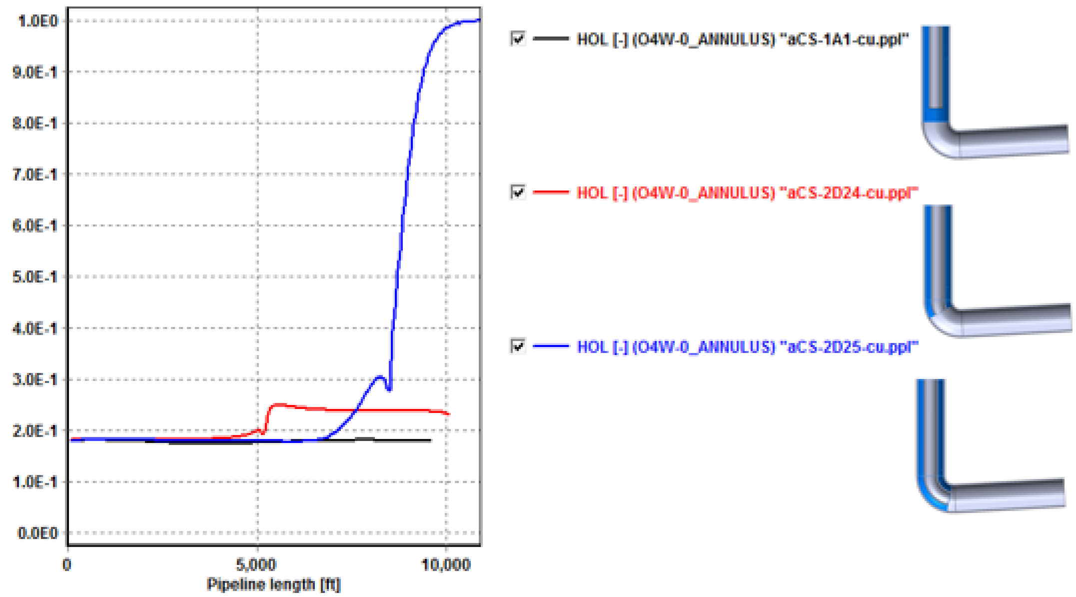


Figure 4.47. Hold-Up At Time=10min Of Annulus Due To Tubing Depth Variation

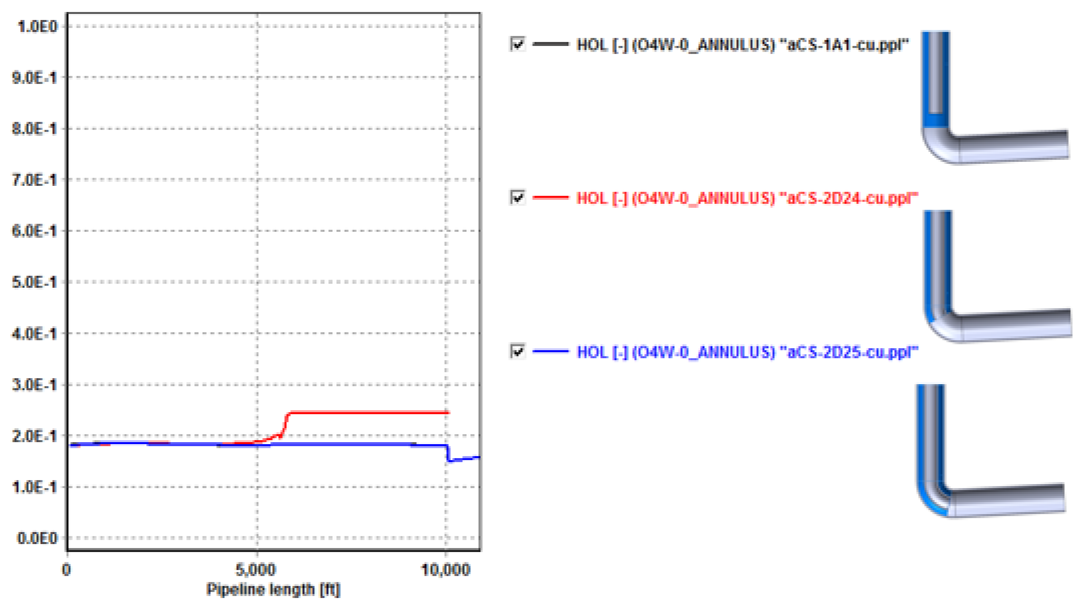


Figure 4.48. Hold-Up At Time=40min Of Annulus Due To Tubing Depth Variation

Figure 4.49 shows the hold-up for the tubing when the simulation starts. Figure 4.50 illustrates the hold-up after 18min.

Figure 4.51 indicates that the hold-up reached the lowest value for the tubing section after 30min of nitrogen injection.

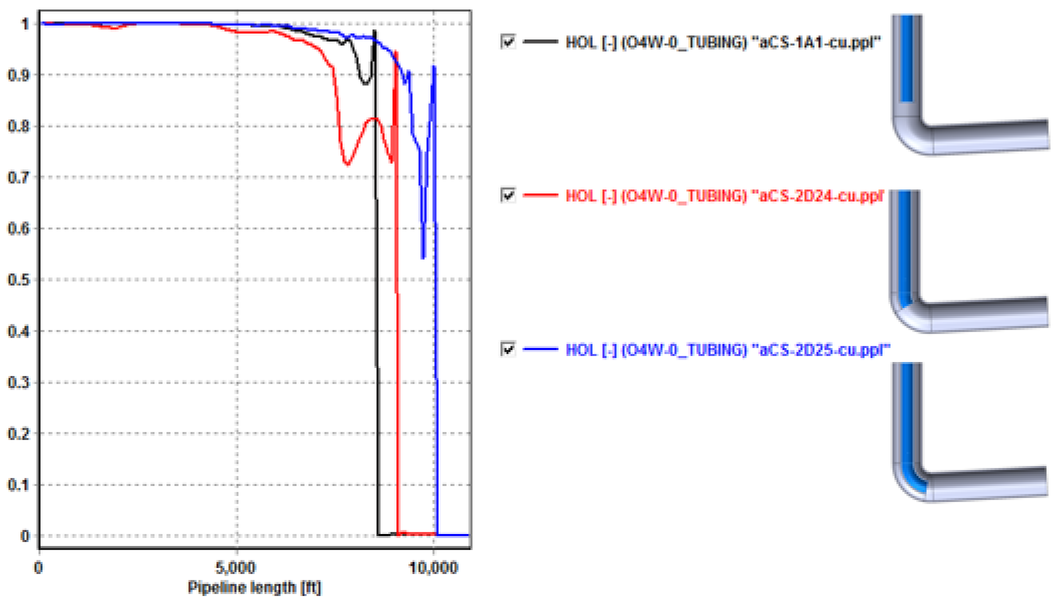


Figure 4.49. Hold-Up At Time=0min Of Tubing Due To Tubing Depth Variation

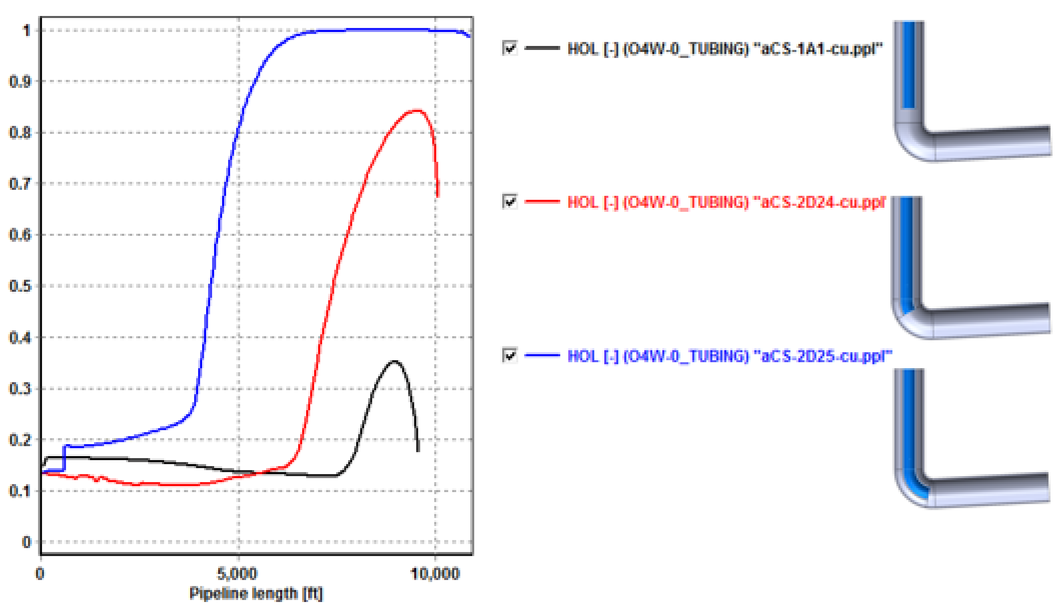


Figure 4.50. Hold-Up At Time=18min Of Tubing Due To Tubing Depth Variation

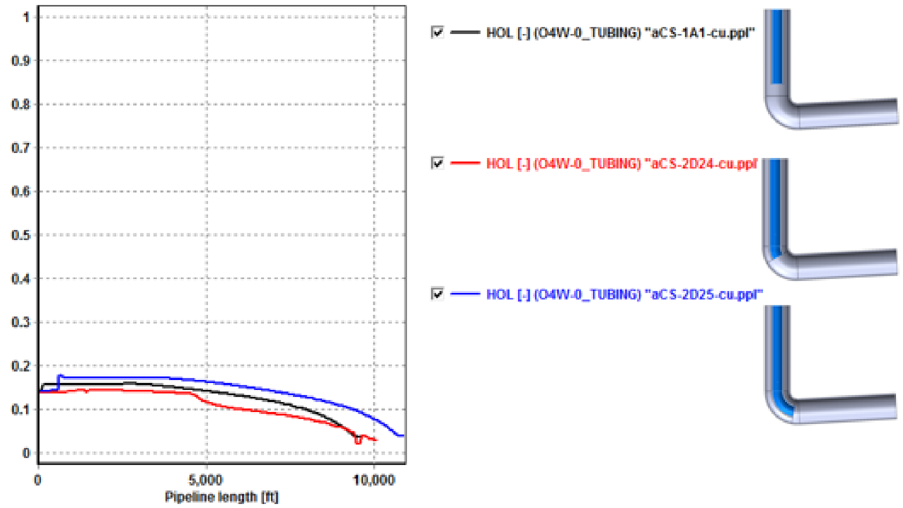


Figure 4.51. Hold-Up At Time=30min Of Tubing Due To Tubing Depth Variation

Figure 4.52 shows the hold-up for the lateral section after 20min of nitrogen injection. Figure 4.53 shows the hold-up after 50min of injection.

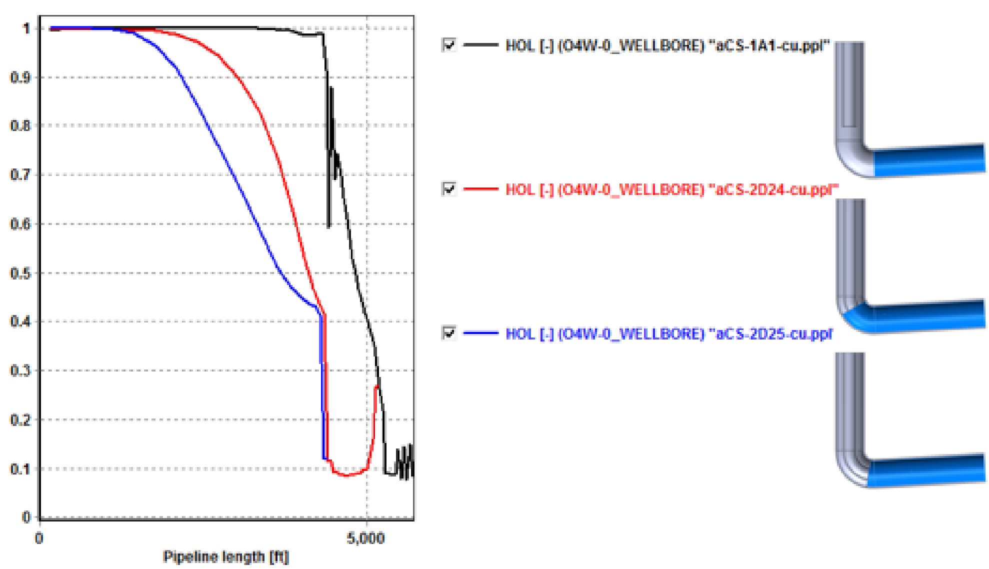


Figure 4.52. Hold-Up At Time=20min Of Lateral Due To Tubing Depth Variation

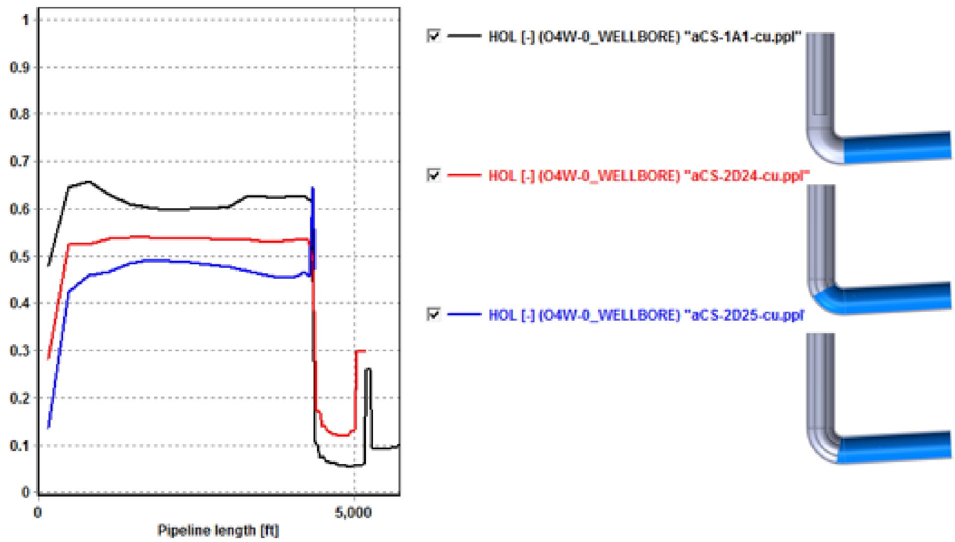


Figure 4.53. Hold-Up At Time=50min Of Lateral Due To Tubing Depth Variation

4.4. VARIATION OF FRAC FLUID PLASTIC VISCOSITY

4.4.1. Pressure. Figure 4.54 shows the pressure profile for all cases after the nitrogen stops being injected.

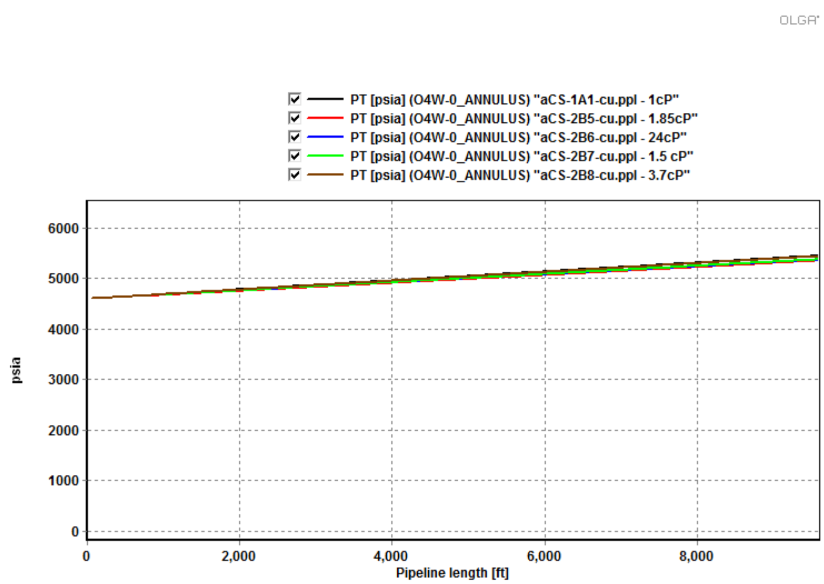


Figure 4.54. Pressure At Time=60min Of Annulus Due To Frac Fluid Plastic Viscosity Variation

Figure 4.55 illustrates the pressure profile for the tubing when the unloading process ends.

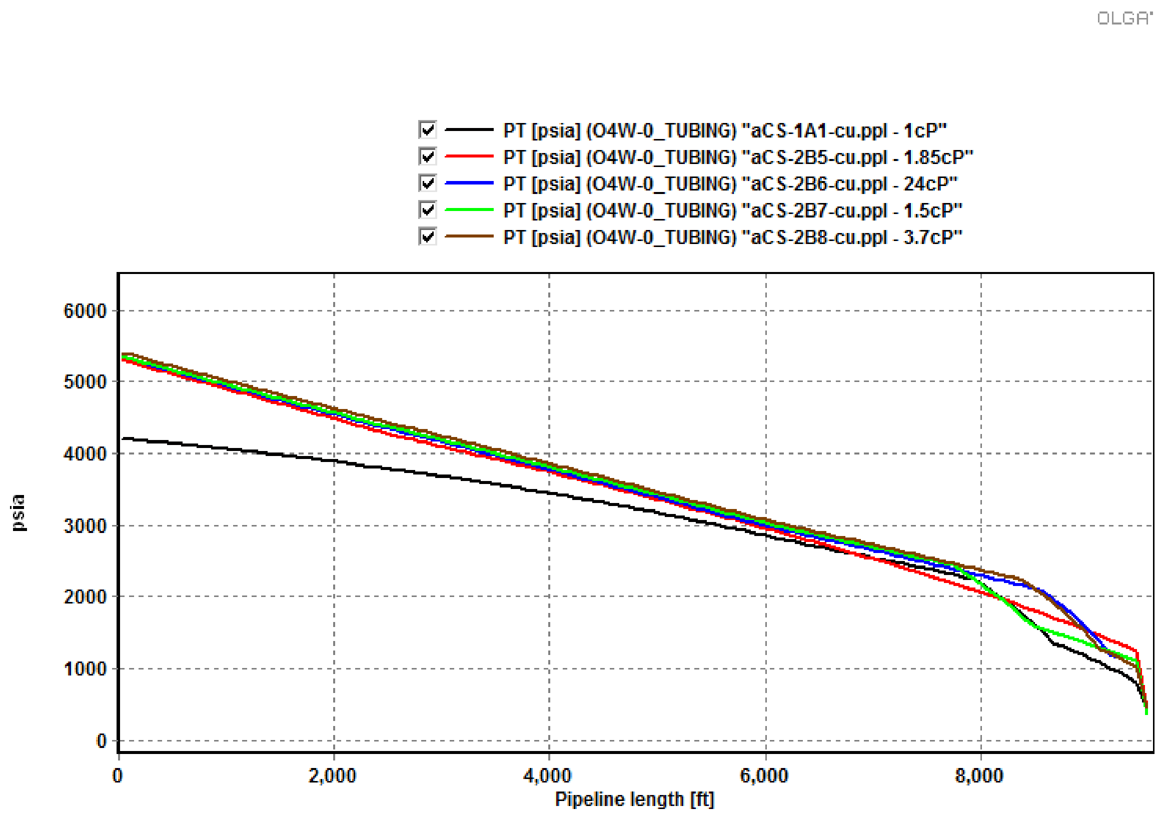


Figure 4.55. Pressure At Time=60min Of Tubing Due To Frac Fluid Plastic Viscosity Variation

Figure 4.56 shows the pressure at the lateral when the unloading process ends, and the reservoir is ready to produce gas by its own.

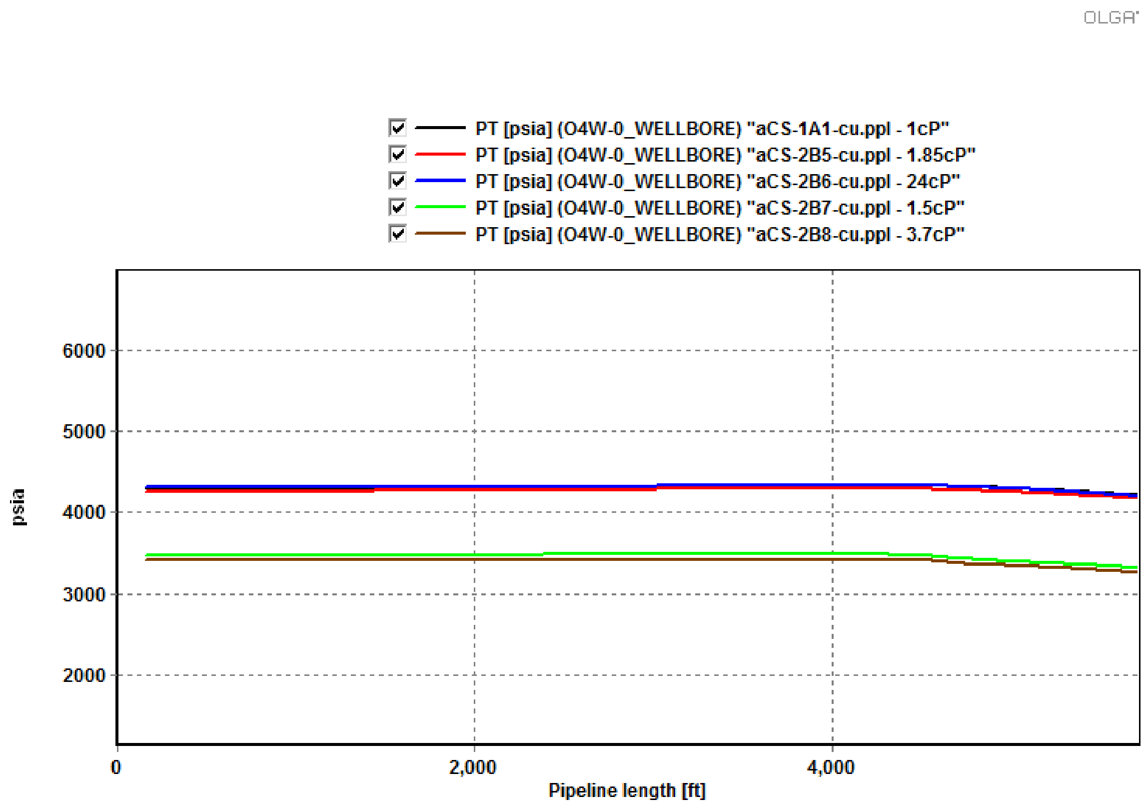


Figure 4.56. Pressure At Time=60min Of Lateral Due To Frac Fluid Plastic Viscosity Variation

4.4.2. Hold-Up. Figure 4.57 shows the hold-up at the annulus when the unloading process starts.

Figure 4.58 shows the hold-up reaches its lowest value after 5min of nitrogen injection.

Figure 4.59 shows the hold-up for the annulus after the unloading process ends after injecting nitrogen.

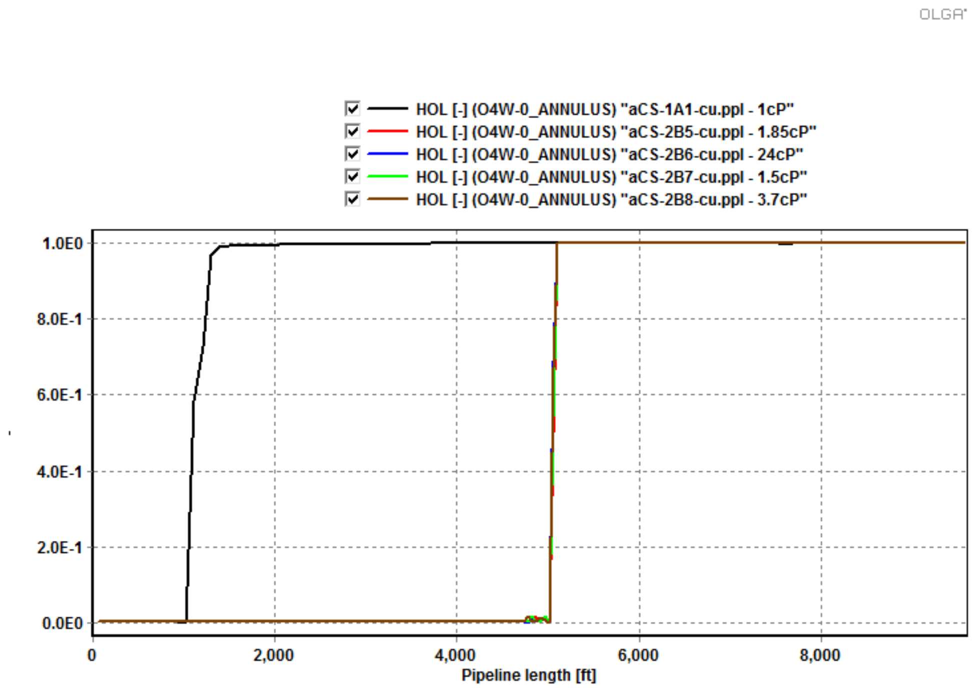


Figure 4.57. Hold-Up At Time=0min Of Annulus Due To Frac Fluid Plastic Viscosity Variation

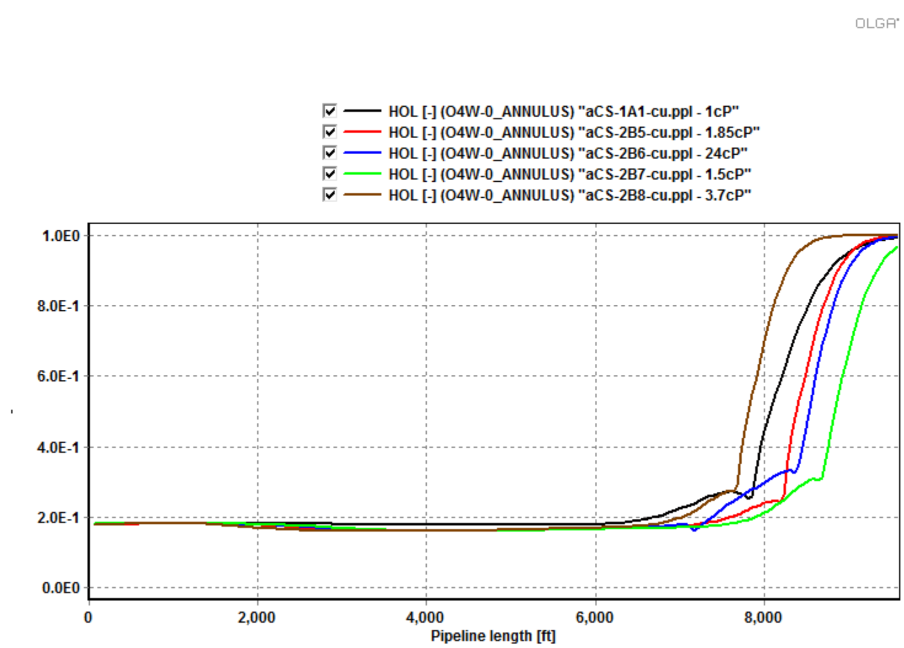


Figure 4.58. Hold-Up At Time=5min Of Annulus Due To Frac Fluid Plastic Viscosity Variation

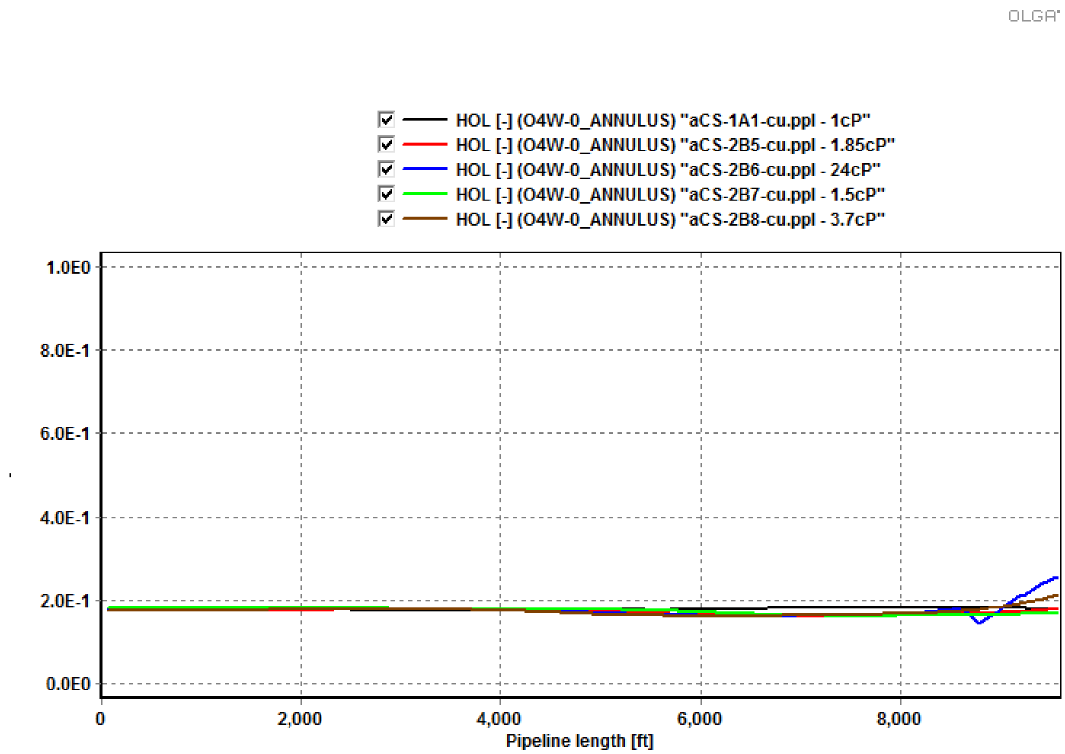


Figure 4.59. Hold-Up At Time=10min Of Annulus Due To Frac Fluid Plastic Viscosity Variation

Figure 4.60 shows the hold-up for the tubing when the simulation starts.

Figure 4.61 illustrates the hold-up after 10min.

Figure 4.62 indicates that the hold-up reached the lowest value for the tubing section after 15min of nitrogen injection.

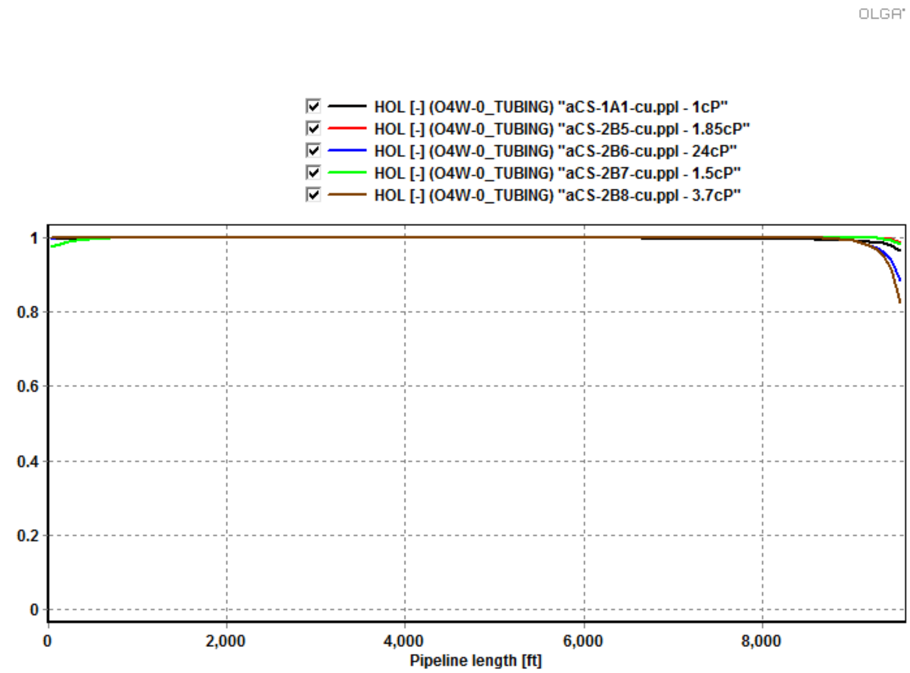


Figure 4.60. Hold-Up At Time=0min Of Tubing Due To Frac Fluid Plastic Viscosity Variation

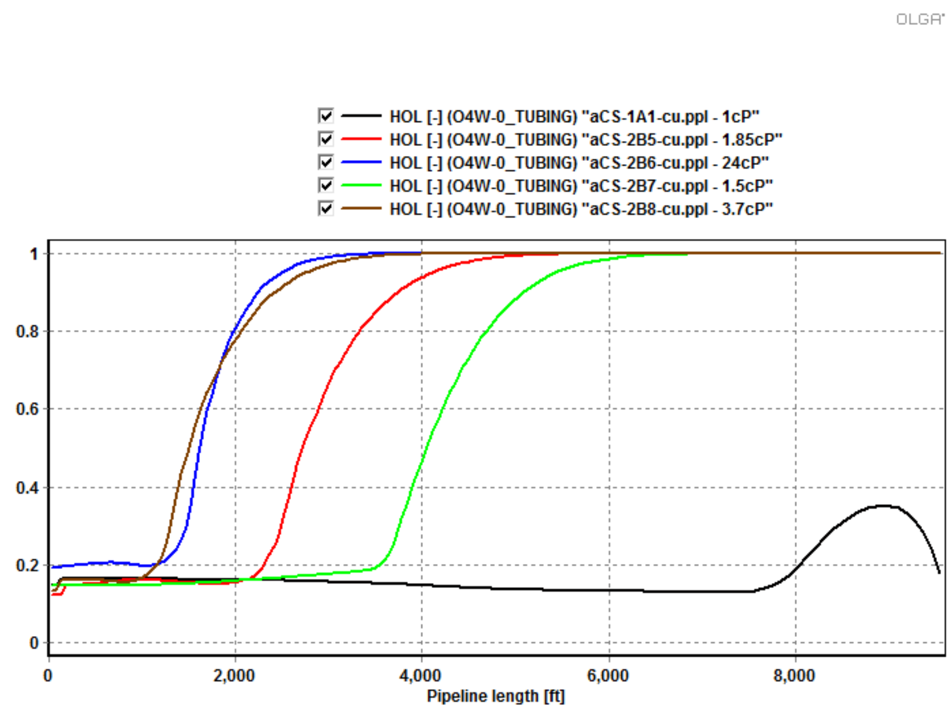


Figure 4.61. Hold-Up At Time=10min Of Tubing Due To Frac Fluid Plastic Viscosity Variation

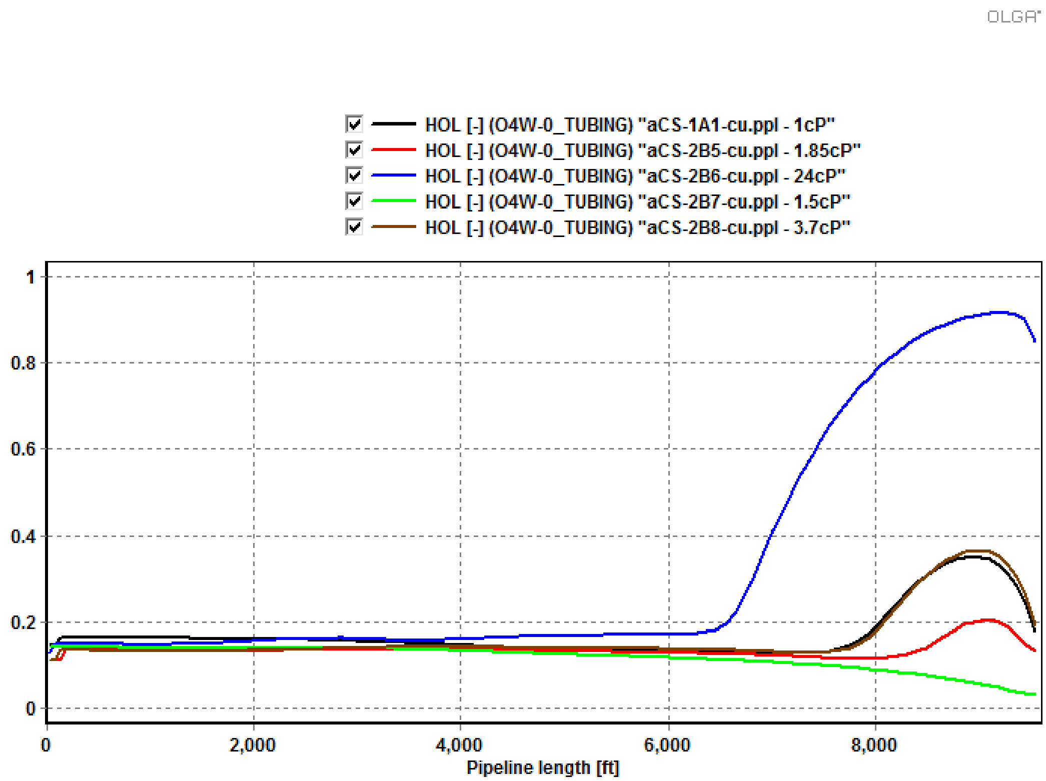


Figure 4.62. Hold-Up At Time=15min Of Tubing Due To Frac Fluid Plastic Viscosity Variation

Figure 4.63 shows the hold-up for the lateral section after 10min of nitrogen injection.

Figure 4.64 shows the hold-up after 60min of injection.

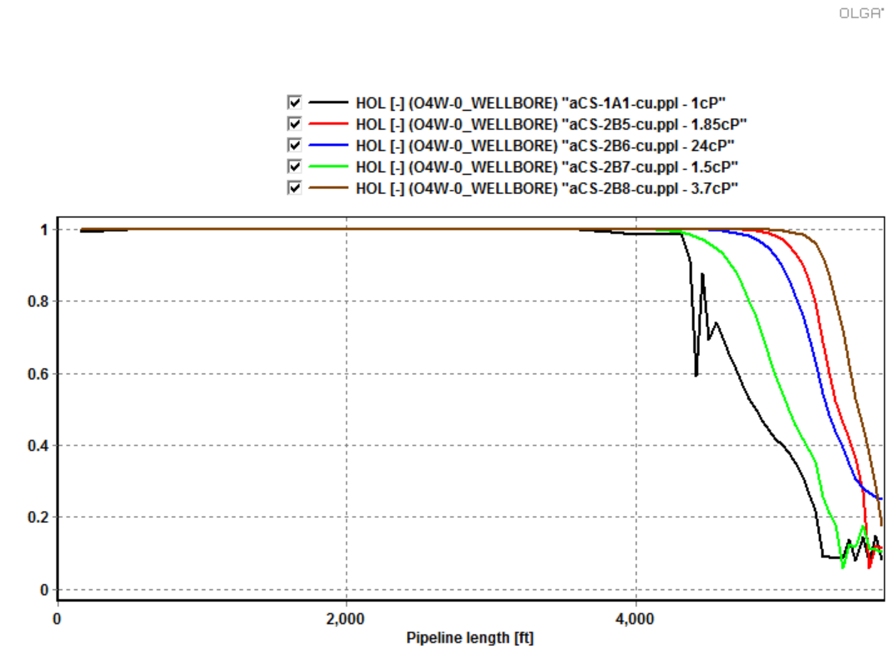


Figure 4.63. Hold-Up At Time=10min Of Lateral Due To Frac Fluid Plastic Viscosity Variation

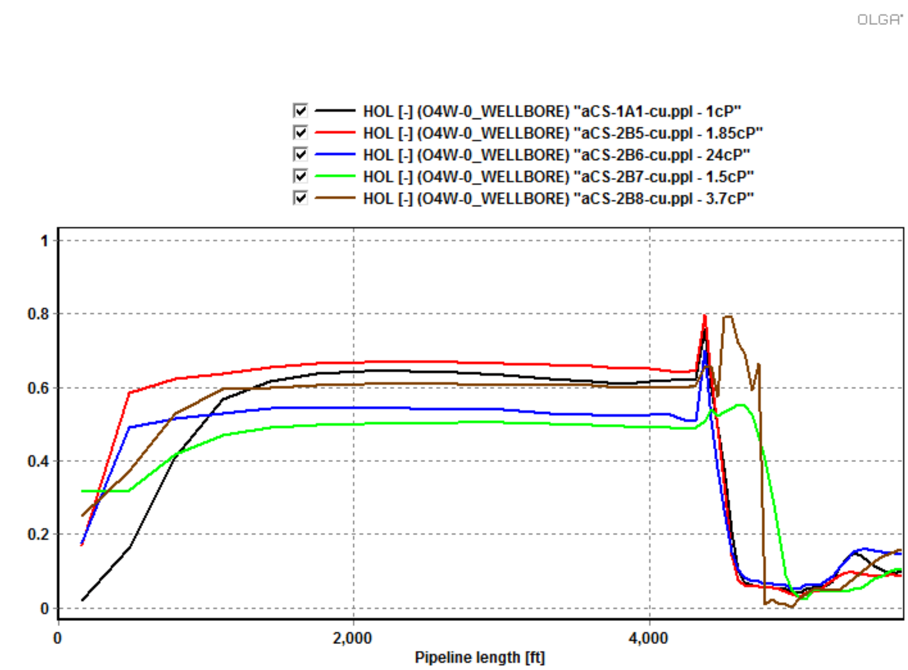


Figure 4.64. Hold-Up At Time=60min Of Lateral Due To Frac Fluid Plastic Viscosity Variation

4.5. MINIMUM NITROGEN VOLUME TO UNLOAD

The following results are calculated based on the minimum time to unload the tubing. In order words, the time stops when the tubing is clear from the frac fluid. Table 4.1, Table 4.2, Table 4.3, Table 4.4 show the plastic viscosity, injection pressure, injection mass rate and deepening tubing string respectively.

Table 4.1. Plastic Viscosity Variation

Case of Study	Plastic Viscosity	IF Mass Rate	Time to unload	Ni Mass	Ni Gas Density	Ni Volume
	[cP]	[lb/s]	[s]	[lb]	[lb/ft3]@SC	[ft3]
1	1	1.1	1005	1105.5	0.0725	15,248.28
7	1.5	1.1	1020	1122	0.0725	15,475.86
5	1.85	1.1	1083	1191.3	0.0725	16,431.72
8	3.7	1.1	1131	1244.1	0.0725	17,160.00
6	24	1.1	1200	1320	0.0725	18,206.90

Table 4.2. Injection Pressure Variation

Case of Study	Injection Pressure	IF Mass Rate	Time to unload	Ni Mass	Ni Gas Density	Ni Volume
	[psi]	[lb/s]	[s]	[lb]	[lb/ft3]@SC	[ft3]
14	4400	1.1	1320	1452	0.0725	20,027.59
15	4600	1.1	1261	1387.1	0.0725	19,132.41
16	4800	1.1	1202	1322.2	0.0725	18,237.24
17	5000	1.1	1140	1254	0.0725	17,296.55
18	5200	1.1	1081	1189.1	0.0725	16,401.38

Table 4.3. Injection Mass Rate Variation

Case of Study	Injection Pressure	IF Mass Rate	Time to unload	Ni Mass	Ni Gas Density	Ni Volume
	[psi]	[lb/s]	[s]	[lb]	[lb/ft3]@SC	[ft3]
19	4600	1	1263	1263	0.0725	17,420.69
20	4600	1.1	1255	1380.5	0.0725	19,041.38
21	4600	1.2	1231	1477.2	0.0725	20,375.17
22	4600	1.3	1211	1574.3	0.0725	21,714.48
23	4600	1.4	1202	1682.8	0.0725	23,211.03

Table 4.4. Deepening Tubing String

Case of Study	Tubing Depth	IF Mass Rate	Time to unload	Ni Mass	Ni Gas Density	Ni Volume
	[ft]	[lb/s]	[s]	[lb]	[lb/ft3]@SC	[ft3]
1	9606	1.1	1200	1320	0.0725	18,206.90
24	10120	1.1	1326	1458.6	0.0725	20,118.62
25	10920	1.1	1584	1742.4	0.0725	24,033.10

4.5.1. Frac Fluid Plastic Viscosity. Figure 4.65 illustrates the correlation between the time to unload and the frac fluid plastic viscosity.

Figure 4.66 shows the relationship between the minimum volume of nitrogen to unload the well versus the frac fluid plastic viscosity.

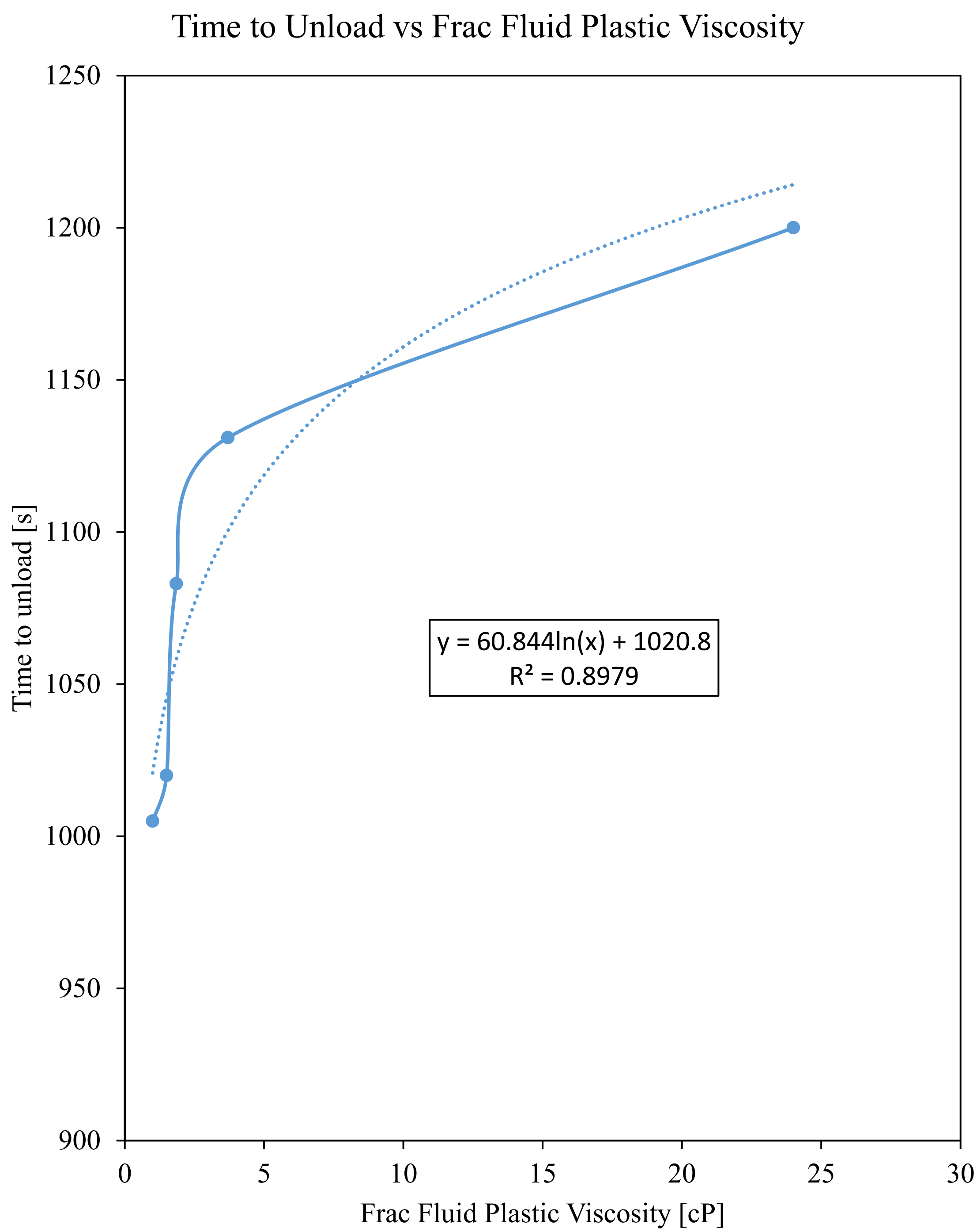


Figure 4.65. Time To Unload Vs. Frac Fluid Plastic Viscosity

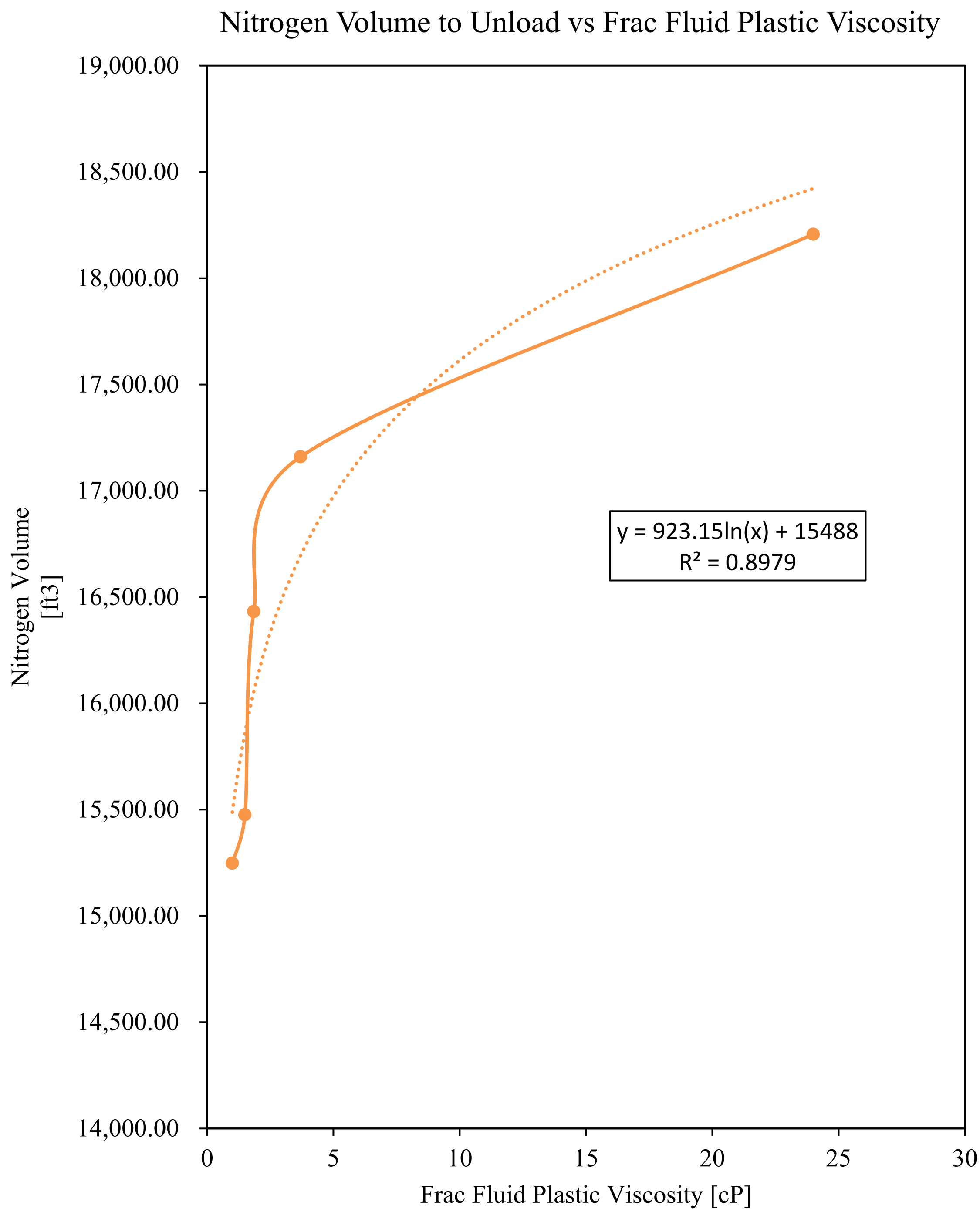


Figure 4.66. Nitrogen Volume To Unload Vs. Frac Fluid Plastic Viscosity

4.5.2. Nitrogen Injection Pressure. Figure 4.67 illustrates the correlation between the time to unload and nitrogen injection pressure. Figure 4.68 shows the relationship between the minimum volume of nitrogen to unload the well and nitrogen injection pressure.

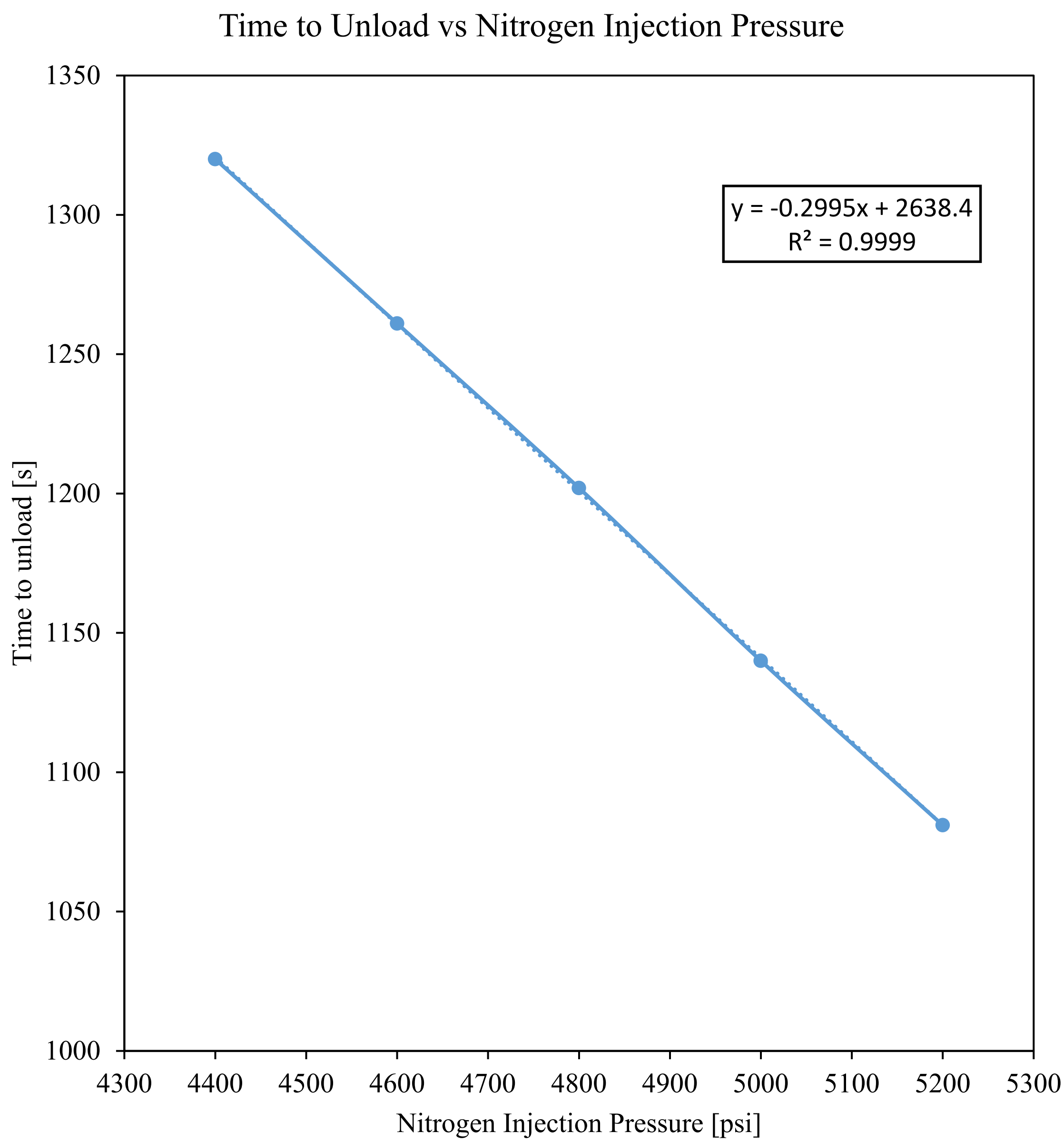


Figure 4.67. Time To Unload Vs. Nitrogen Injection Pressure

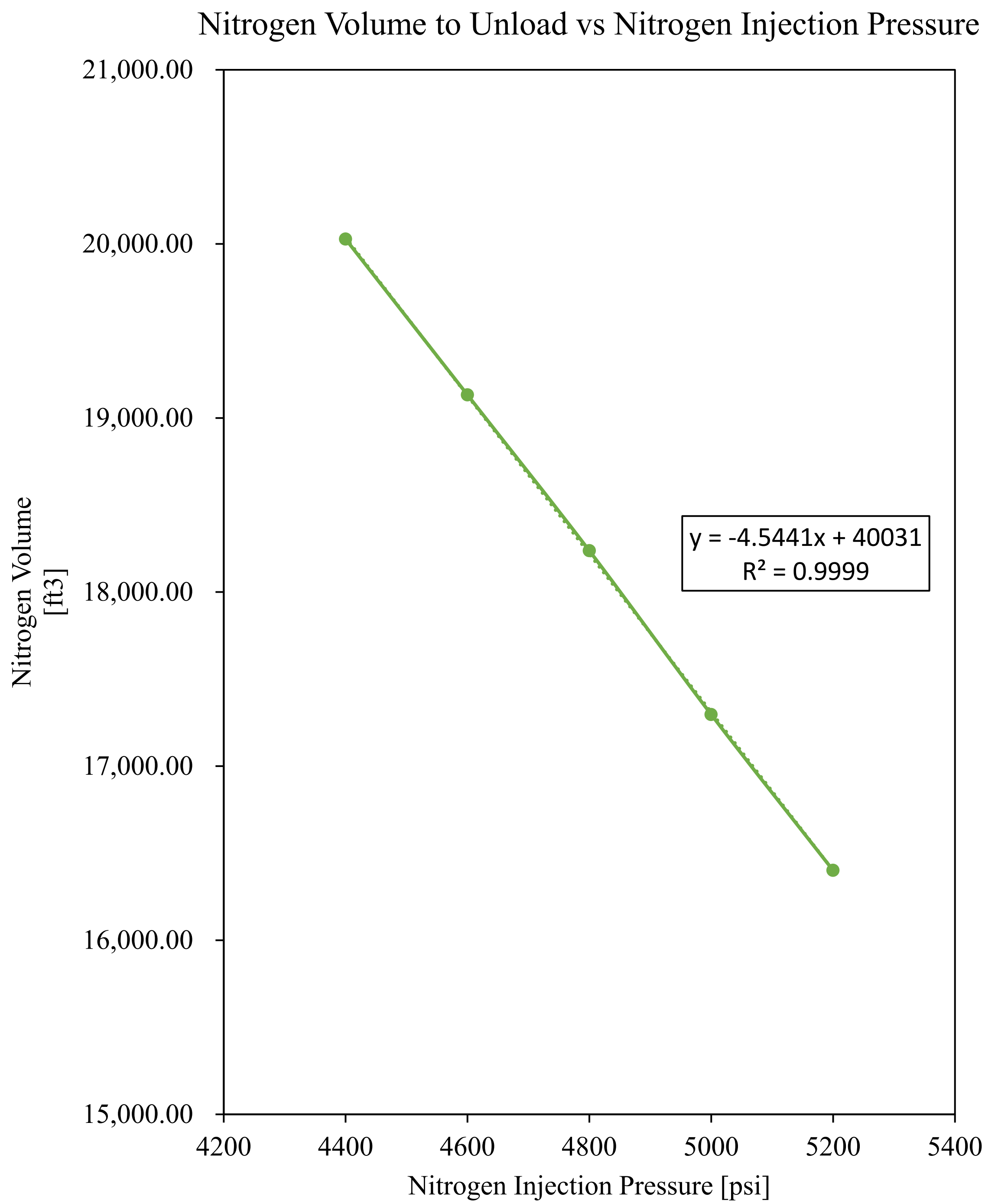


Figure 4.68. Nitrogen Volume Vs. Nitrogen Injection Pressure

4.5.3. Nitrogen Injection Mass Rate. Figure 4.69 illustrates the correlation between the time to unload and the nitrogen injection mass rate. Figure 4.70 shows the relationship between the minimum volume of nitrogen to unload the well and the nitrogen injection mass rate.

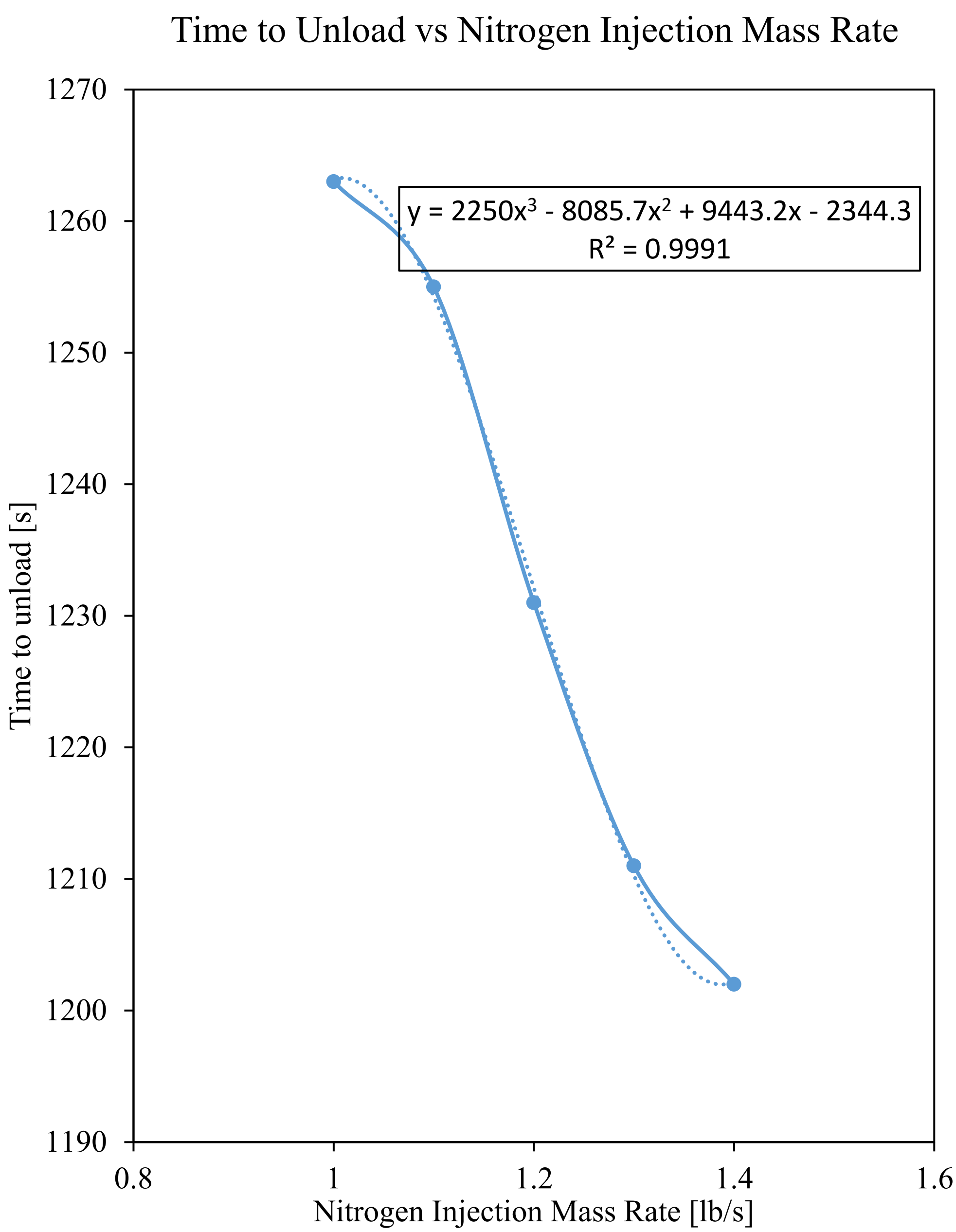


Figure 4.69. Time To Unload Vs. Nitrogen Injection Mass Rate

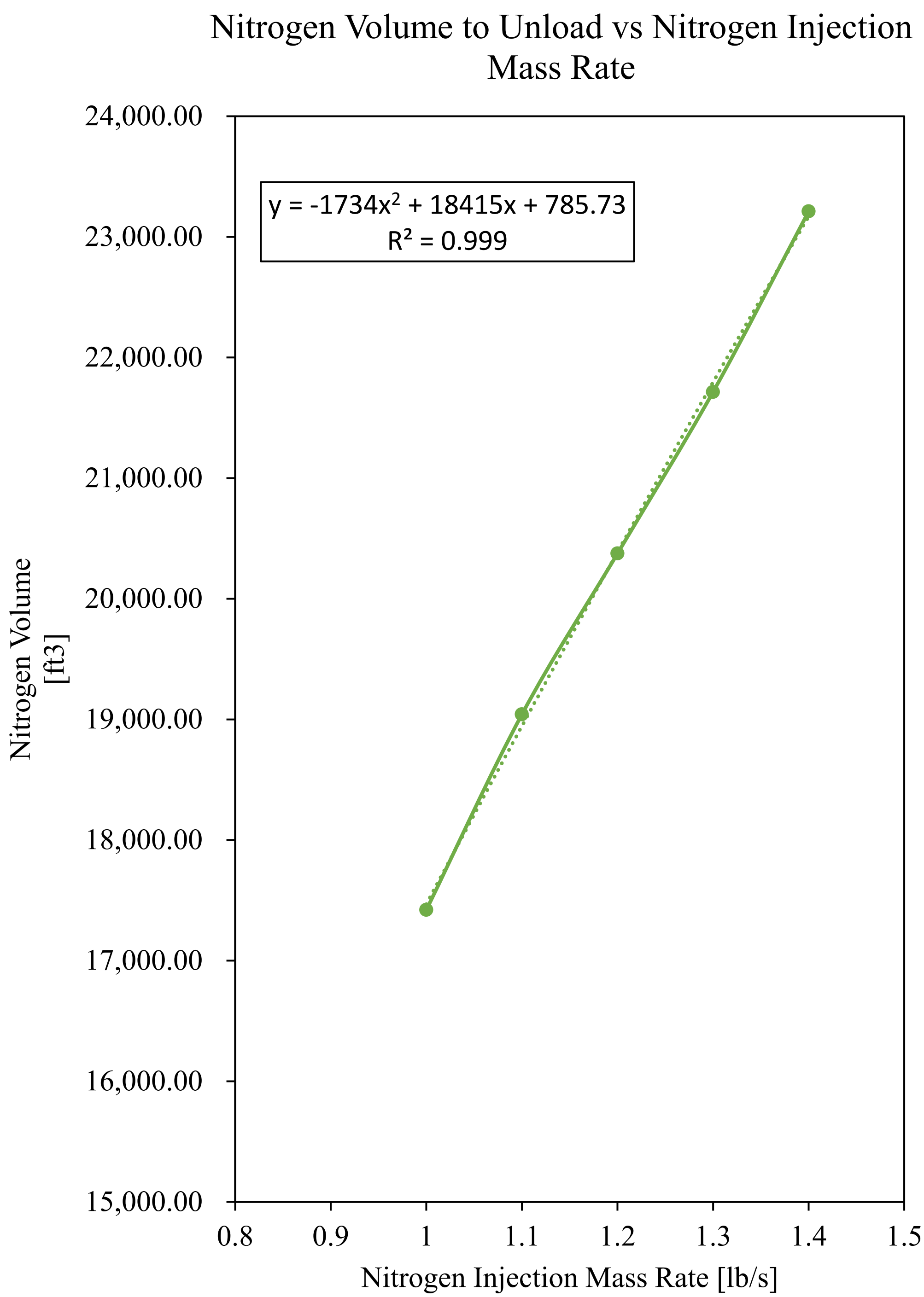


Figure 4.70. Nitrogen Volume Vs. Nitrogen Injection Mass Rate

4.5.4. Tubing Depth MD. Figure 4.71 illustrates the correlation between the time to unload and the tubing depth. Figure 4.72 shows the relationship between the minimum volume of nitrogen to unload the well and the tubing depth. Figure 4.73 shows the lateral hold-up when deepening the tubing along the deviated section up to the entrance of the lateral section.

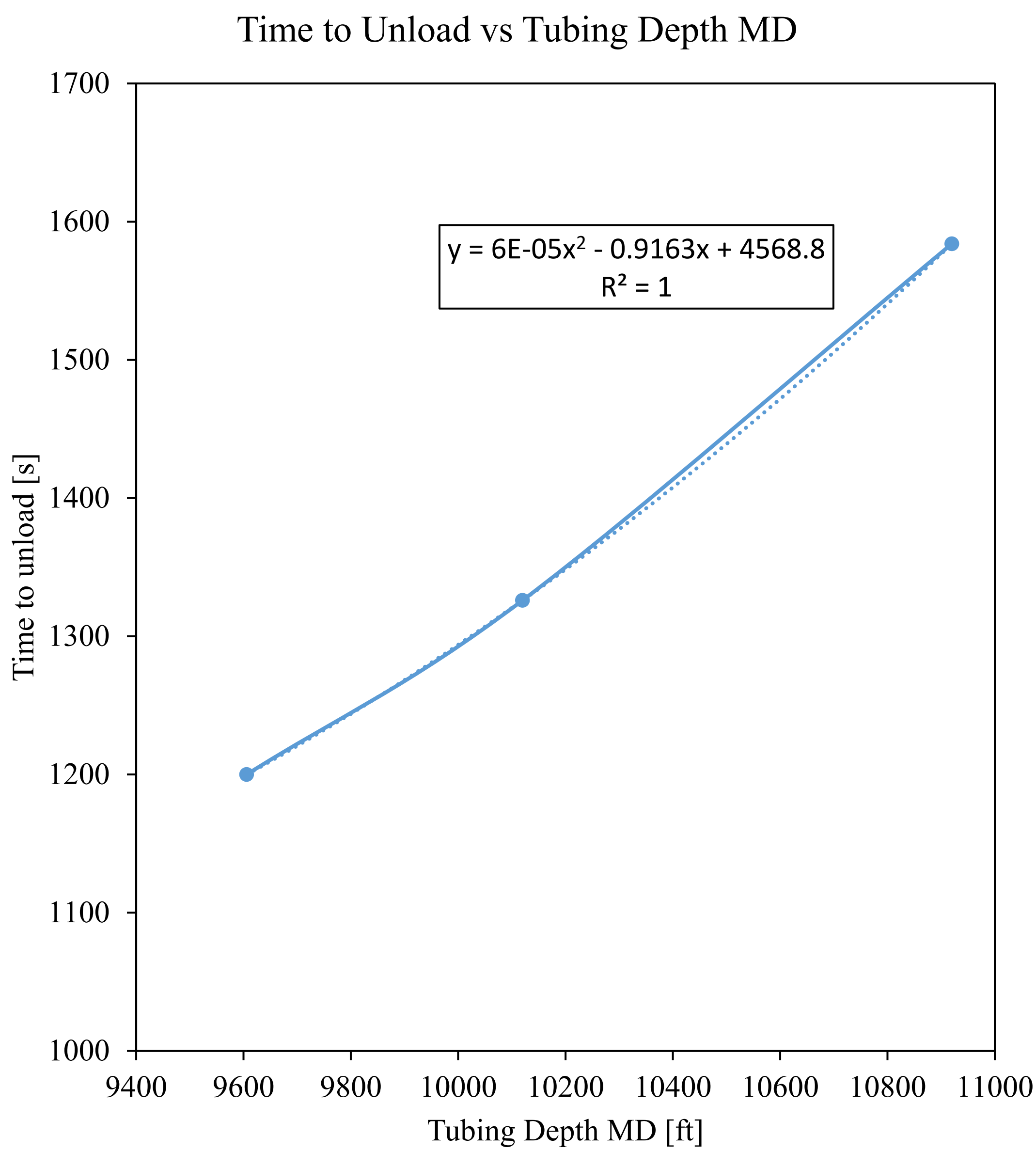


Figure 4.71. Time To Unload Vs. Tubing Depth MD

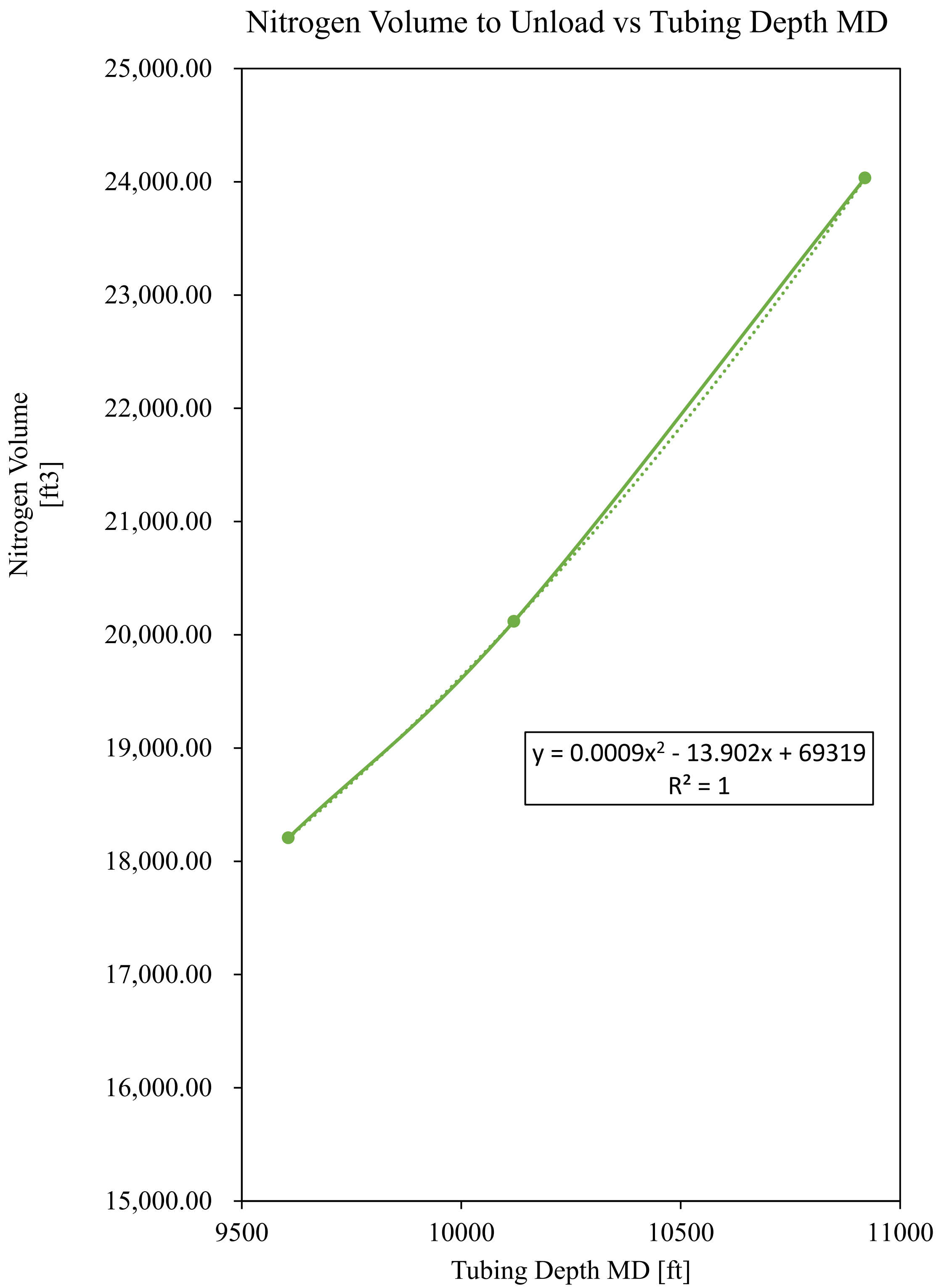


Figure 4.72. Nitrogen Volume To Unload Vs. Tubing Depth MD

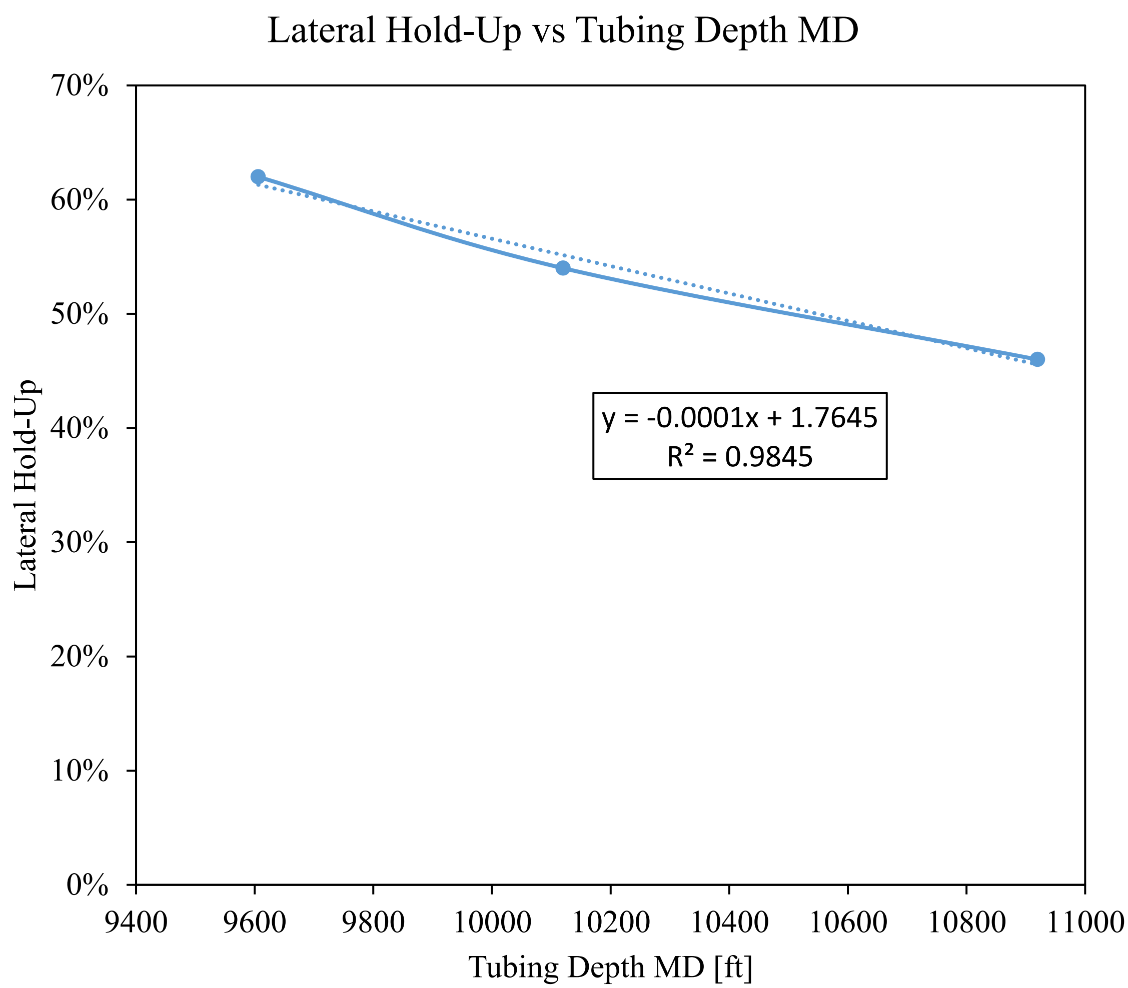


Figure 4.73. Lateral Hold-Up Vs. Tubing Depth MD

4.6. VARIATION OF TUBING AND CASING

Figure 4.74 shows correlations that relate the volume to be displaced and the minimum nitrogen volume to unload based on the tubing size for a 7in casing. Figure 4.75 shows correlations that relate the volume to be displaced and the minimum nitrogen volume to unload based on the tubing size for a 5 ½ in casing. Figure 4.76 shows correlations that relate the volume to be displaced and the minimum nitrogen volume to unload based on the tubing size for a 4 ½ in casing.

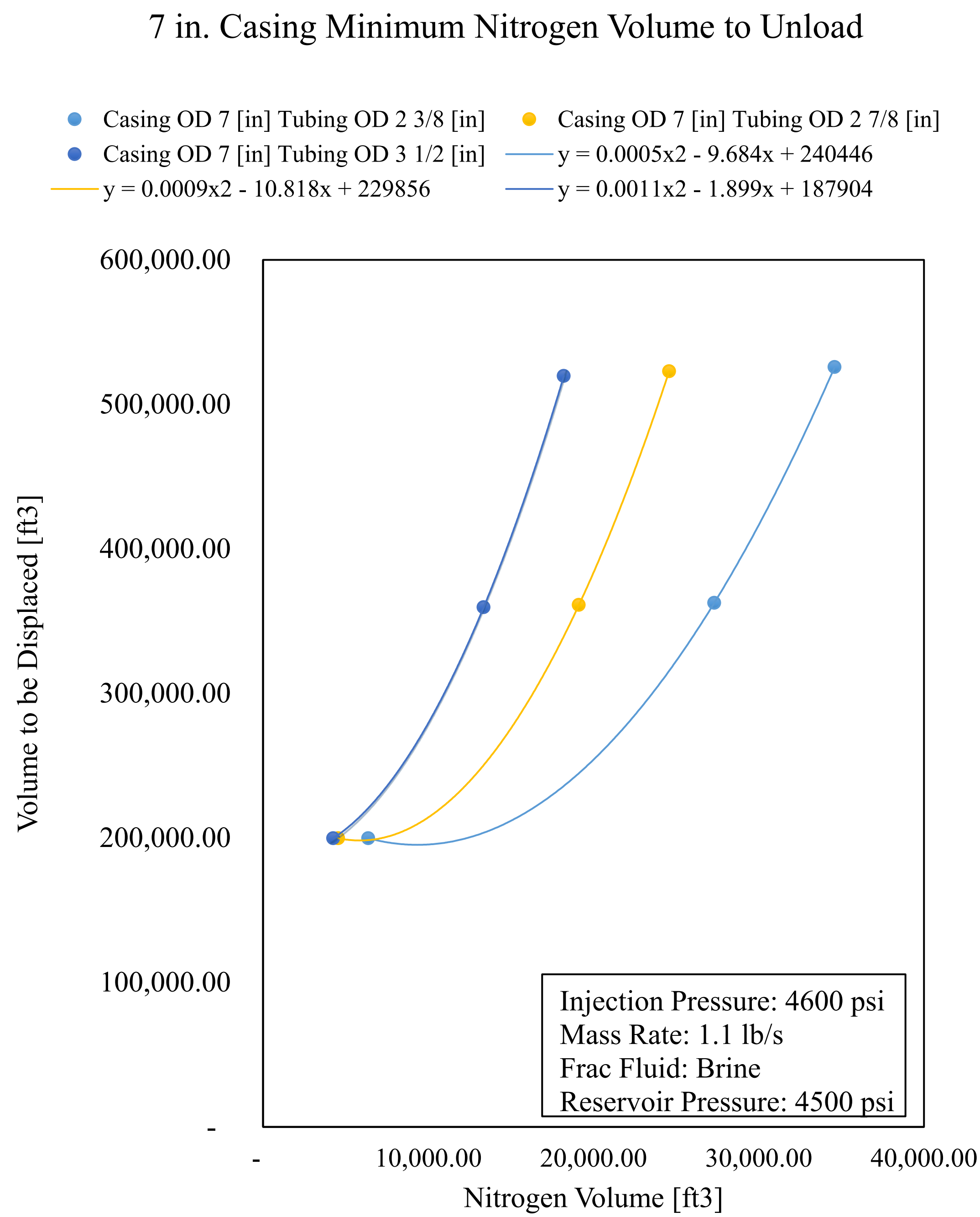


Figure 4.74. Minimum Nitrogen Volume To Unload 7in. Casing

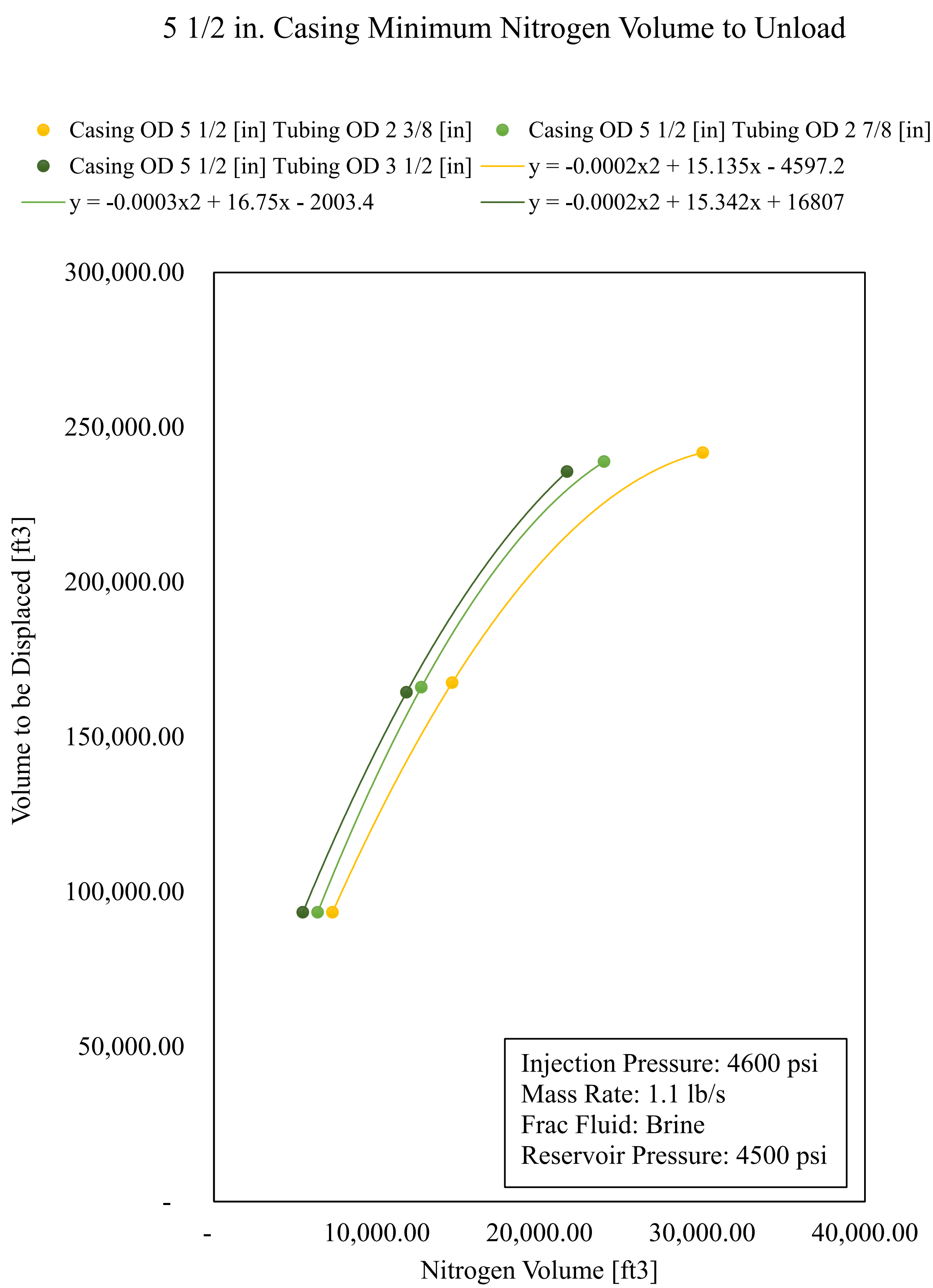


Figure 4.75. Minimum Nitrogen Volume To Unload 5 ½ in. Casing

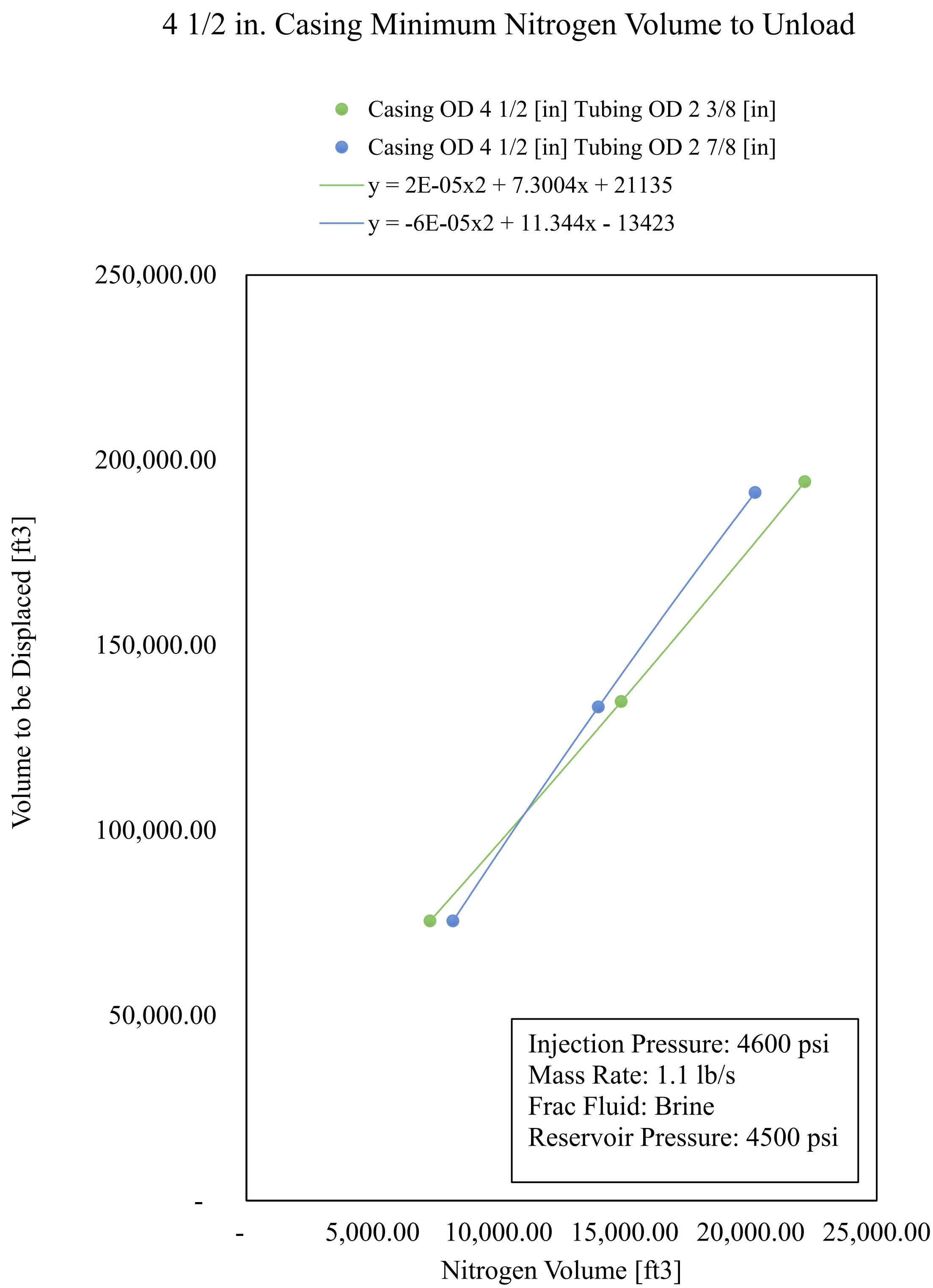


Figure 4.76. Minimum Nitrogen Volume To Unload 4 ½ in. Casing

4.7. METHANE VS NITROGEN UNLOAD

The difference between using methane or nitrogen are displayed in Figure 4.77 and Figure 4.78 for volume to unload and time to unload, respectively.

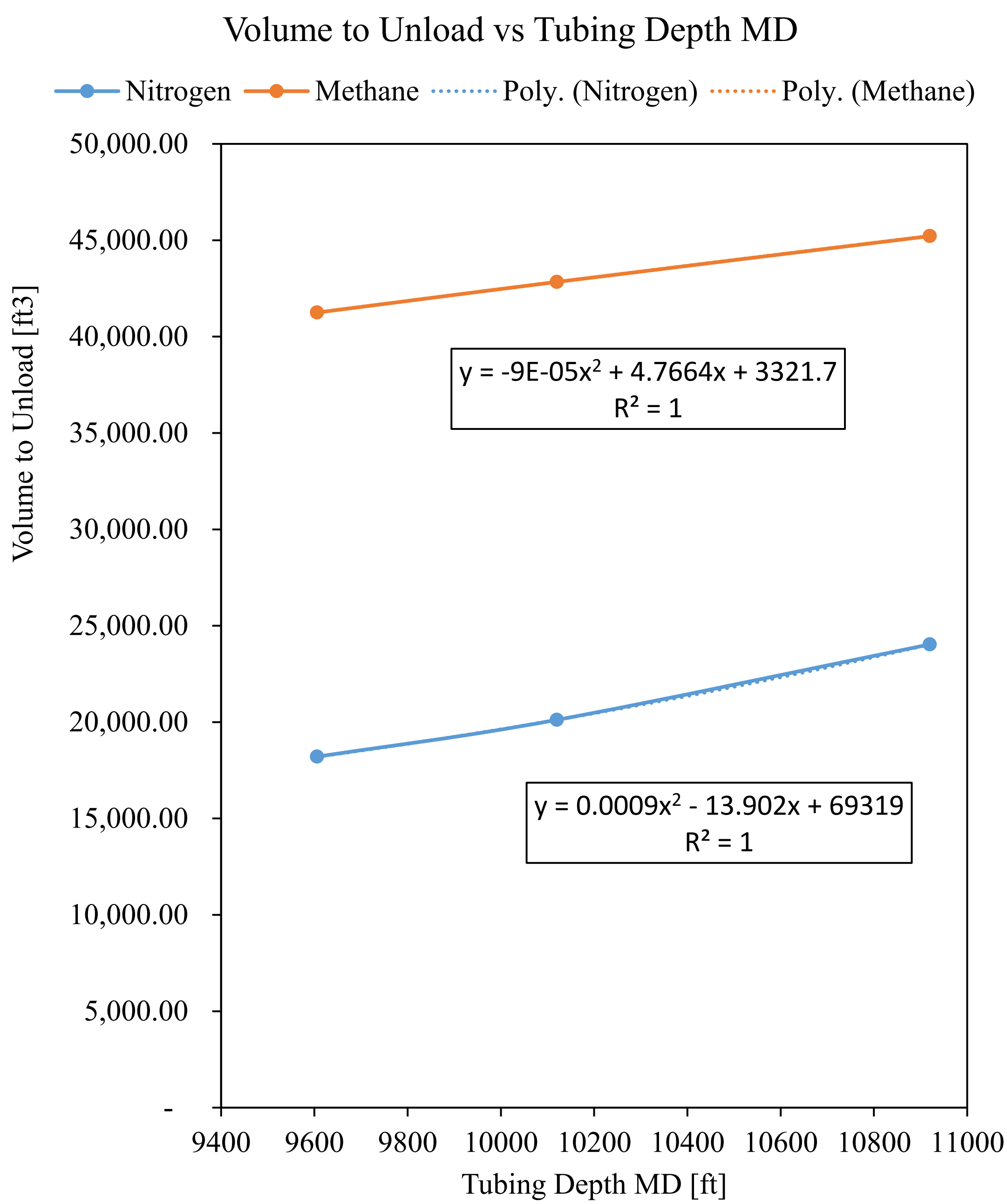


Figure 4.77. Nitrogen And Methane Volume To Unload Vs. Tubing Depth MD

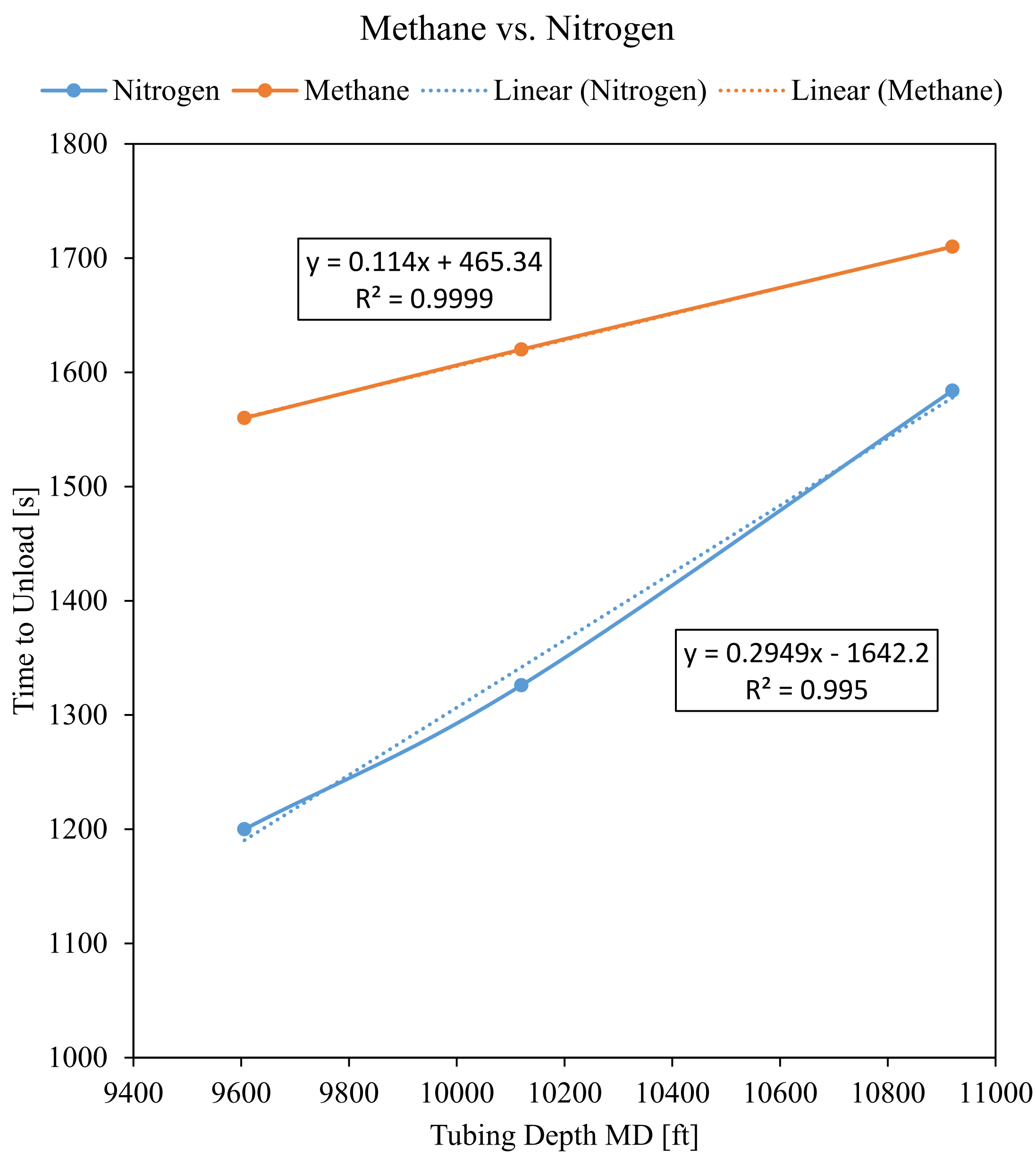


Figure 4.78. Nitrogen And Methane Time To Unload Vs. Tubing Depth MD

4.8. TOE UP – DOWN EFFECT

By varying the lateral section from, toe down (88.3 Deg), horizontal toe, and toe up (91.67 Deg), Figure 4.79 shows the nitrogen volume and time to unload.

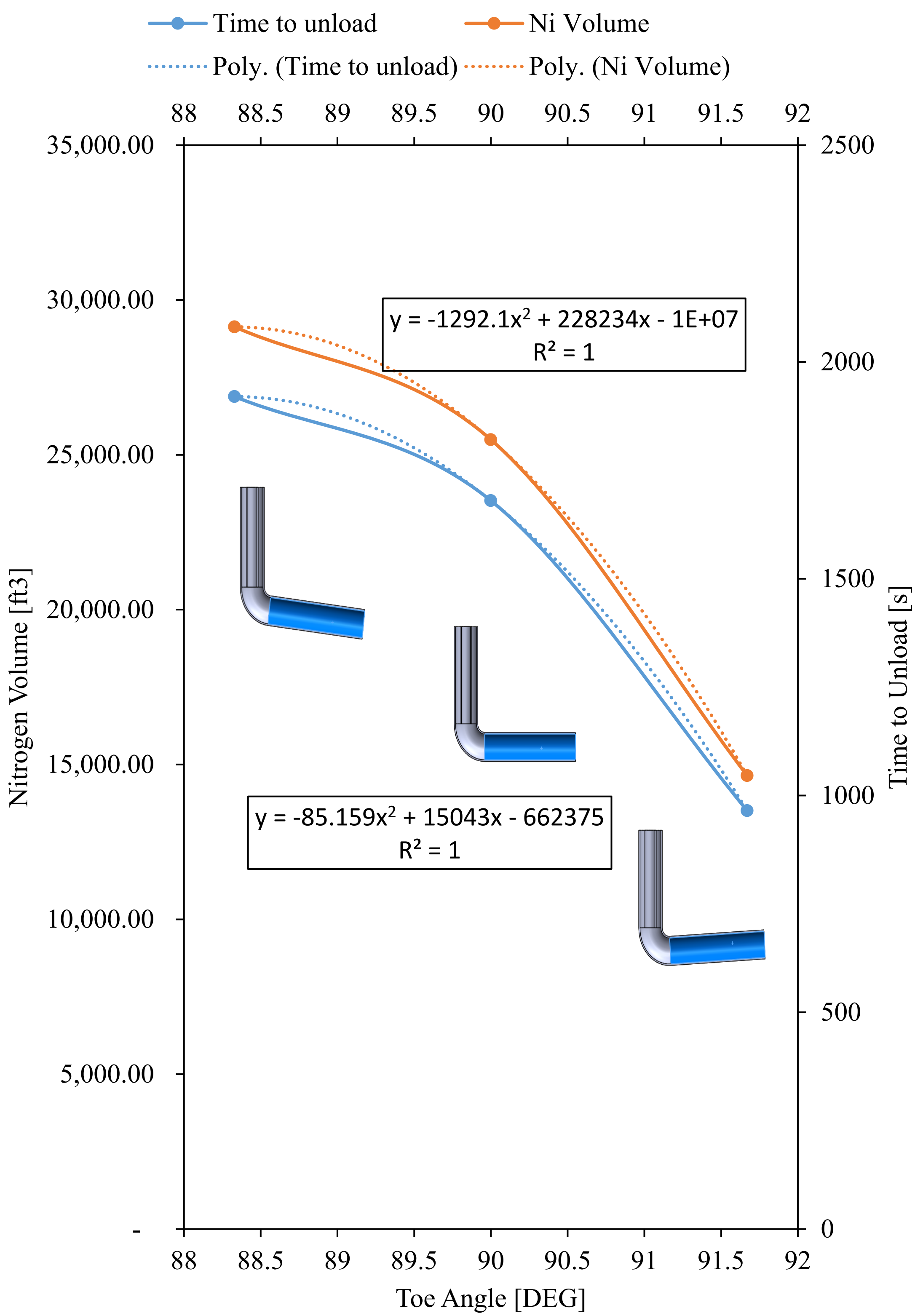


Figure 4.79. Toe Effect

5. SUMMARY AND CONCLUSIONS

5.1. RESEARCH SUMMARY AND CONTRIBUTIONS

This work presented a transient multiphase flow simulation for unloading of frac hit gas wells. The research was conducted using OLGA by Schlumberger as a transient multiphase flow simulator.

Case studies were based on active gas well located in Hawk Ville at the Eagle Ford Shale. For the parametric study, a range of frac fluid plastic viscosity was used. A wide range of parameters for nitrogen injection pressure and mass rate were used.

The parametric analysis helped to create plots and correlations. From the best of the author's knowledge, this work is one of the first published research in open literature. This work can set up the foundation of future simulations for unloading gas wells due to frac hits.

5.2. CONCLUSIONS

Several conclusions are drawn from this work as follow:

- Transient multiphase flow model simulation was successfully constructed in OLGA.
- The unloading behavior with nitrogen was similar when the well survey varies from vertical to 60DEG deviation. The unloading behavior varied for a horizontal well with a lateral section.
- The nitrogen volume required to unload increased while the frac fluid plastic viscosity increased, following a logarithmic relationship.

- The nitrogen volume decreased while nitrogen injection pressure increased, following a linear relationship.
- The nitrogen volume increased while nitrogen injection mass rate increased, following a 2^{nd} order polynomial relationship.
- The nitrogen volume increased while tubing depth increased, following a 2^{nd} polynomial relationship.
- The time to unload increased while the frac fluid plastic viscosity increased, following a logarithmic relationship.
- The time to unload decreased while nitrogen injection pressure increased, following a linear relationship.
- The time to unload decreased while nitrogen injection mass rate increased, following a 3^{rd} order polynomial relationship.
- The time to unload increased while tubing depth increased, obeying a 2^{nd} order polynomial equation.
- By increasing the nitrogen injection mass rate, the time to unload is reduced; however, the nitrogen volume increased. This matter would mean that it would require more nitrogen to unload even though less time to unload. The operator company could save money by using less time the compressor for injecting nitrogen, but it would increase the expense of buying more nitrogen.
- Deepening the tubing requires more time to unload and more nitrogen. However, it can help clean the lateral section up to 15%. The hold-up is reduced by 0.0001% per foot.

- The amount of nitrogen required to unload is close when the casing varies from 5.5in to 4.5in OD.
- More methane volume is required to unload compared to nitrogen.
- The difference between the time to unload of the methane and nitrogen reduces when deepening the tubing.
- The angle of the lateral section plays an important role in the unloading process. Toe up will help reducing the time and volume to unload because gravity moves the liquid from the toe to the deviated section.

5.3. FUTURE WORK

This work covered many aspects, even so, there is some suggested analysis for future work such as:

- Cost analysis of injecting nitrogen and methane to unload gas wells.
- Study the behavior of the unloading process using natural gas instead of nitrogen. At this moment, oil industry is experimenting with natural gas injection into unloading laterals. Using the simulation models published in this work, by changing some parameters for the unloading fluid from nitrogen to natural gas, this work can contribute with new simulation models that can predict the use and behavior of natural gas into unloading laterals.

APPENDIX A.

PARAMETRIC STUDIES BASED ON CASE STUDY 1A1 CHART

			Well Trajectory			Casing			Tubing					Surface		Reservoir			Column of Liquid @SC				Injection Fluid			
Objectives	Case of Study		Section			OD	ID	Weight	OD	ID	Weight	Location	ratio	Surface Temperature	Surface Pressure	Reservoir Temperature	Reservoir Pressure	IPR (Linear)	Type	Density	Plastic Viscosity	Yield Stress*	Type	IF Temperature	IF Pressure	IF Mass Rate
	No	[Name]	Vertical	Deviated	Lateral	[in]	[in]	[lbm/ft]	[in]	[in]	[lbm/ft]	[ft]		[F]	[psia]	[F]	[psia]	[scf/d/psi]		[lb/ft3]	[cP]	[psia]		[F]	[psia]	[lb/s]
1A	1	Base Case	YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.1
2A	2		YES	NO	NO	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.1
	3		YES	30 DEG	NO	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.1
	4		YES	60 DEG	NO	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.1
2B	5	Base Case	YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	SlickWater	62.42	1.85	0	Nitrogen	104	4600	1.1
	6		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Gel #20	63.05	24	0	Nitrogen	104	4600	1.1
	7		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	SlickWater + Friction Reducer MP20A01	61.8	1.5	0	Nitrogen	104	4600	1.1
	8		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	SlickWater + Friction Reducer MP20A02	61.8	3.7	0	Nitrogen	104	4600	1.1
2C	14		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4400	1.1
	15		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.1
	16		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4800	1.1
	17		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	5000	1.1
	18		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	5200	1.1
	19		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1
	20		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.1
	21		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.2
	22		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.3
	23		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.4
2D	24		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	10120	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.1
	25		YES	YES	90 DEG	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	10920	0.43	59	40	285	4500	1150	Brine	68.67	1	0	Nitrogen	104	4600	1.1

APPENDIX B.

PARAMETRIC STUDIES VARYING CASING AND TUBING SIZE CHART

		Well Trajectory	Casing			Tubing				Liquid Level	Volume to be held up					NIP at 4600psi
Case of Study		Measure depth	OD	ID	Weight	OD	ID	Weight	Location	from tubing up		IF Mass Ra	Time to unload	Ni Mass	Ni Gas Density	Ni Volume
Section	[Name]	[ft]	[in]	[in]	[lbm/ft]	[in]	[in]	[lbm/ft]	[ft]	[ft]	[ft3]	[lb/s]	[s]	[lb]	[lb/ft3]@SC	[ft3]
1	Nitrogen	15345	7	6 2/3	13	2 3/8	2 1/6	2.6	9606	10	199,788.19	1.1	420	462	0.0725	6,372.41
2	Nitrogen	15345	7	6 2/3	13	2 7/8	2 5/8	3.7	9606	10	199,785.15	1.1	300	330	0.0725	4,551.72
3	Nitrogen	15345	7	6 2/3	13	3 1/2	3 1/4	4.8	9606	10	199,781.78	1.1	280	308	0.0725	4,248.28
4	Nitrogen	15345	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	10	93,387.13	1.1	480	528	0.0725	7,282.76
5	Nitrogen	15345	5 1/2	4 5/9	23	2 7/8	2 5/8	3.7	9606	10	93,384.09	1.1	420	462	0.0725	6,372.41
6	Nitrogen	15345	5 1/2	4 5/9	23	3 1/2	3 1/4	4.8	9606	10	93,380.72	1.1	360	396	0.0725	5,462.07
7	Nitrogen	15345	4 1/2	4	10	2 3/8	2 1/6	2.6	9606	10	75,523.86	1.1	480	528	0.0725	7,282.76
8	Nitrogen	15345	4 1/2	4	10	2 7/8	2 5/8	3.7	9606	10	75,520.82	1.1	540	594	0.0725	8,193.10
9	Nitrogen	15345	7	6 2/3	13	2 3/8	2 1/6	2.6	9606	4803	362,640.96	1.1	1800	1980	0.0725	27,310.34
10	Nitrogen	15345	7	6 2/3	13	2 7/8	2 5/8	3.7	9606	4803	361,181.00	1.1	1260	1386	0.0725	19,117.24
11	Nitrogen	15345	7	6 2/3	13	3 1/2	3 1/4	4.8	9606	4803	359,562.03	1.1	880	968	0.0725	13,351.72
12	Nitrogen	15345	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	4803	167,532.25	1.1	965	1061.5	0.0725	14,641.38
13	Nitrogen	15345	5 1/2	4 5/9	23	2 7/8	2 5/8	3.7	9606	4803	166,072.29	1.1	840	924	0.0725	12,744.83
14	Nitrogen	15345	5 1/2	4 5/9	23	3 1/2	3 1/4	4.8	9606	4803	164,453.32	1.1	780	858	0.0725	11,834.48
15	Nitrogen	15345	4 1/2	4	10	2 3/8	2 1/6	2.6	9606	4803	134,776.20	1.1	980	1078	0.0725	14,868.97
16	Nitrogen	15345	4 1/2	4	10	2 7/8	2 5/8	3.7	9606	4803	133,316.24	1.1	920	1012	0.0725	13,958.62
17	Nitrogen	15345	7	6 2/3	13	2 3/8	2 1/6	2.6	9606	9606	525,833.50	1.1	2280	2508	0.0725	34,593.10
18	Nitrogen	15345	7	6 2/3	13	2 7/8	2 5/8	3.7	9606	9606	522,913.58	1.1	1620	1782	0.0725	24,579.31
19	Nitrogen	15345	7	6 2/3	13	3 1/2	3 1/4	4.8	9606	9606	519,675.65	1.1	1200	1320	0.0725	18,206.90
20	Nitrogen	15345	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	9606	241,832.06	1.1	1980	2178	0.0725	30,041.38
21	Nitrogen	15345	5 1/2	4 5/9	23	2 7/8	2 5/8	3.7	9606	9606	238,912.15	1.1	1580	1738	0.0725	23,972.41
22	Nitrogen	15345	5 1/2	4 5/9	23	3 1/2	3 1/4	4.8	9606	9606	235,674.22	1.1	1430	1573	0.0725	21,696.55
23	Nitrogen	15345	4 1/2	4	10	2 3/8	2 1/6	2.6	9606	9606	194,152.15	1.1	1460	1606	0.0725	22,151.72
24	Nitrogen	15345	4 1/2	4	10	2 7/8	2 5/8	3.7	9606	9606	191,232.24	1.1	1330	1463	0.0725	20,179.31
25	Methane	15345	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	9606	4803	167,532.25	1.1	1560	1716	0.0416	41,250.00
26	Methane	15345	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	10120	5317	167,133.41	1.1	1620	1782	0.0416	42,836.54
27	Methane	15345	5 1/2	4 5/9	23	2 3/8	2 1/6	2.6	10920	6117	166,512.64	1.1	1710	1881	0.0416	45,216.35

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VITA

Miguel Angel Cedeno Moreno received his bachelor's degree in Mechanical Engineering from Higher Polytechnic University of Chimborazo (Escuela Superior Politecnica de Chimborazo), Riobamba - Ecuador in November 2014. He was awarded as Summa Cum Laude and received the Best Graduate of Mechanical Engineering Department Award. He worked at Andes Steel Industry (Industria Acero de los Andes), Quito - Ecuador as Junior Mechanical Engineer during his senior year in multi-million manufacturing projects for refineries designing oil and gas pipelines, storage oil tanks and heat transfer exchangers. He received a mechanical design professional certification by AutoDesk in Florida, USA in AutoCAD. He obtained a mechanical design professional certification by Dassault Systemes in Florida, USA in SolidWorks. He developed coding skills for artificial intelligence and deep neural machine learning while working as private data scientist. He enrolled in University of South Florida in January 2015 and transferred to Missouri University of Science and Technology in May 2016 to pursue a master's degree in Petroleum Engineering. He graduated with his master's degree in December 2017. In August 2016, he obtained a scholarship from Missouri University of Science and Technology to pursue a Ph.D. degree in Petroleum Engineering with Dr. Shari Dunn-Norman as his advisor, researching Transient Multi-Phase Flow Simulation for Unloading Gas Wells. He received certification by NExT Schlumberger in Houston, TX regarding OLGA Well Assurance which is the software used in his dissertation. He received his Ph.D. degree in Petroleum Engineering from Missouri University of Science and Technology in May 2019.